CALIFORNIA
ENERGY
COMMISSION

Workshop Report
on
DISTRIBUTED GENERATION INTERCONNECTION RULES

Docket No. 99-DIST-GEN (2)

STAFF REPORT

APRIL 2000
P700-00-003

Gray Davis, *Governor*

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Companies actively participating in the working group process included:

California Air Resources Board
California Municipal Utilities Association
California Independent System Operator
Capstone Turbine
CPUC – Office of Ratepayer Advocates
Cogeneration Association of California/Energy Producers and Users Coalition
Engine World
Enron
Future Resources Associates
Hetch Hetchy Water and Power
Honeywell
Intergy
Los Angeles Department of Water and Power
New Energy Inc.
Pacific Gas and Electric
Polaris Group (The)
Redding (City of)
Resource Dynamics Corporation
Riverside Public Utilities
Southern California Edison
San Diego Gas and Electric
Sempra Energy
Sacramento Municipal Utilities District
Southern California Gas Company
Solar Development Corporation
University of California/California State University
VFL Energy Technologies

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INTRODUCTION

The staff of the California Energy Commission hereby submits this report to the Energy Commission's Siting Committee (Committee) pursuant to Order Instituting Investigation OII 99-DIST-GEN(2) issued on November 3, 1999. The purpose of the report is to set forth staff recommendations to the Committee regarding the development of distributed generation interconnection rules. **Staff's recommendations to the Committee are based upon how well and to what extent the interconnection working groups' products reflect the guiding principles set forth in this report. Ultimately, the staff recommendations are based upon consideration of whether the work products remove barriers to distributed generation technologies entering the market.**

The Committee has scheduled a hearing on April 25, 2000 to hear public comments about this report. Written comments on the report and discussion at the hearing will be due on May 2, 2000. Subsequent to the deadline for filing written comments, it is anticipated that the Committee will forward a final report to the full Commission for adoption towards the end of May with final recommendations delivered to the California Public Utilities Commission (CPUC) by late June 2000. The CPUC will further consider these recommendations in its current rulemaking investigating distributed generation (CPUC Docket R.99-10-025).

Background

The adoption of D.99-10-065 and the opening of R.99-10-025 at the CPUC in October 1999 provided a procedural roadmap for addressing issues related to distributed generation. The decision was the result of collaborative efforts among the CPUC, the Energy Commission, and the Electricity Oversight Board.

On November 3, 1999 the Energy Commission opened an investigation to identify barriers to the development of distributed generation technologies by utility interconnection and other rules, and then to develop, if possible, recommendations to remove those barriers. Based upon D.99-10-065, the Committee stated that this proceeding would address the following issues:

- Scope of technologies covered by the interconnection rules;
- Need for interim standards;
- Technical issues surrounding interconnection rules;
- Safety issues;
- Feasibility of type testing;
- Information and training for government agencies;
- Advanced communications and metering for scheduling and dispatch;
- Changes to utility tariffs explaining interconnection rules.

On December 6, 1999, the Siting Committee held a workshop to begin the investigation. More than 100 people attended the workshop, representing a wide range of interests with respect to distributed generation and distribution competition. The Committee issued an Order dated December 16, 1999 that set forth the process that the interested parties would use to address the issues.

Guiding Principles

In its December 1999 Order, the Committee stated that great weight would be given to developing rules that promote consumer choice while protecting the reliability of the distribution system. Also, the Committee was not interested in developing rules which could negatively impact residential and commercial customers in the interest of promoting distributed generation technologies for the benefit of the larger industrial and electric generation customers. The Committee then set forth five principles to guide the work of the working groups:

- Rules, protocols, and processes should be clear and transparent.
- Rules should be technology neutral, except where differential requirements can be fully justified by safety or other legitimate concerns.
- A level playing field should be established for all distributed generation providers.
- Rules should be uniform throughout California, and nationwide if possible.
- Utility distribution companies should be fairly compensated for distribution services that support distributed generation installations and customers.

Goal of the Report

The goal of the staff report is to provide the Committee with proposed rule language that could apply to all distributed generation customers seeking to interconnect with the three investor-owned utilities in California regulated by the CPUC.

The recommendations are based largely on the work of a group of technical and non-technical stakeholders during the past four months. A general description of the workshop process employed is provided in Part I of this report. Part II addresses how the working group process responded to each of the 13 points raised in the CPUC's initial Order Instituting Rulemaking (OIR) that apply to the Energy Commission's willingness to lead the interconnection workshop process. Part III is the most critical feature of this report, providing a section-by-section overview of the proposed interconnection rule language. Working group concerns specific to individual sections are addressed here as well as staff recommendations on particular language. Part IV addresses concerns not specific to particular rule language. Part V restates staff's general recommendations to the Committee. The report concludes with a discussion about next steps required in this process. Attachment A contains the proposed rule language for each section as well as specific comments submitted by working group members during the process. Attachment B includes a work in progress of a sample application form and an interconnection agreement.

I. WORKSHOP PROCESS

Implementing the provisions outlined in the December order, staff employed a workshop process that entailed the use of working groups to develop a recommendation for the CPUC. Originally staff sought to establish three working groups: one to address technical issues, one for non-technical issues, and one for policy issues. Based on logistical concerns expressed by stakeholders about covering multiple meetings, staff reduced the number of working groups from three to two.

Initial working group meetings were held on January 4-5, 2000 to identify the major technical and non-technical issues the groups should consider in developing interconnection rules. At the meetings, the groups decided to produce a series of proposals relating to revised CPUC Rule 21 tariff language, including technical and non-technical specifications for DG customers; representative interconnection agreements; and recommendations about the participation of publicly-owned utilities not under CPUC jurisdiction. The California Municipal Utilities Association (CMUA) submitted a proposal regarding the latter issue, which is addressed in the *Next Steps* section of this report.

Additional working group meetings were held on February 1-2, 16 (combined with a staff workshop), 29, as well as March 7, 14, 21, 28.   Meeting locations were rotated throughout the state to allow access to parties with restricted travel budgets. Staff wishes to express its appreciation to SDG&E (2/29, 3/7, 3/21) for hosting three of the meetings and both Edison and PG&E for each hosting one (3/14, and 3/28, respectively).

Beginning with the February 29 meeting, the groups agreed to meet weekly to jointly review proposed Rule 21 tariff language, discuss specific concerns and consider alternative language for each section of the Rule, and raise new issues of concerns. In addition, several subgroups were created to provide added focus on specific issues such as type testing and definitions. Between meetings, issues were further addressed via e-mail, with results compiled and resubmitted to the combined group in time for the next meeting.

In total, approximately 75 people actively participated in the working group process either through attending meetings (or via teleconference), e-mail comments or concerns, or via reviewing various documents distributed each week. The groups and subgroups reflected a wide range of stakeholders, including utilities, DG manufacturers, DG customers, regulators, marketers, and small end-use customer groups. In addition, many of the key representatives responsible for the development of interconnection rules in New York, Texas, and Arizona participated in this process. Many of the same participants are involved in the development of a technical interconnection document at the national level.

II. CPUC OIR INVESTIGATION POINTS

Much of the work performed during this workshop process has been driven by the desire to respond to the 13 topic areas noted in R.99-10-025 and identified in the roadmap decision. These topic areas, shown directly below, are consistent with the eight topic areas noted by the Committee in its December 1999 order.

- The scope of the distributed energy resources (DER) technologies covered by the interconnection rules;
- Whether there should be a size limitation for the distributed generation facilities that are subject to the interconnection rules;
- Development of interconnection standards;
- Safety concerns;
- Whether the differences in distribution systems (e.g. radial vs. networked) can be accommodated as part of any standards;
- The need to develop California standards pending the development of national standards (e.g. IEEE);
- Whether type-testing of standardized distribution units can be used;
- Whether the owner of the facility to be connected to the distribution system can select the interconnection voltage level;
- The extent to which governmental agencies and utility personnel need to be informed about the deployment and impact of distributed generation;
- Whether the owner and operator of an islanded distributed generation installation should be required to notify the UDC or another entity of such facilities;
- Whether advanced communication and metering equipment should be required in order to schedule and dispatch distributed generation in an efficient and effective manner;
- Whether interconnection standards are needed depending on the DER technology that is used, and the size of the distributed generator; and
- Identifying what tariff changes to Rule 21 are needed.

(CPUC R.99-10-025, pgs. 9-10)

Early in the workshop process, the working groups decided to focus their attention on developing proposed Rule 21 tariff language. Table 1 below indicates which OIR topic areas apply the proposed rule language that will be discussed later in this report. A brief discussion of how the workshop report responds to each OIR topic follows. To reduce the level of repetition, this section combines two groups of topic areas: 1) scope of technologies and size limitations, and 2) development of standards and identification of Rule 21 tariff changes.

Table 1
OIR Topics Addressed By Rule 21

OIR topics	Section Number in Proposed Rule 21									
	1	2	3	4	5	6	7	8	App A	App B
1. Scope of technologies	X							X	X	
2. Size limitations									X	
3. Development of standards	X	X	X	X	X	X	X	X	X	X
4. Safety concerns		X		X						X
5. Radial vs. networked distribution systems									X	
6. Need to develop CA standards										
7. Type testing				X						X
8. Selection of voltage level										
9. Gov't agency/utility personnel knowledge of DG		X	X							
10. Notification to UDC of "islanded" DG										
11. Need for advanced communications and metering equipment						X				
12. Variation in standards by DG type and size						X				X
13. Identification of Rule 21 tariff changes	X	X	X	X	X	X	X	X	X	X

OIR Topic #1 (Scope of Technologies) and Topic #2 (Size Limitations)

Interconnection standards represented by the proposed Rule language apply to all types of distributed generation technologies, including storage technologies that substitute for or augment generation. These technologies include, but are not limited to, the established conventional technologies (combustion turbines and internal combustion engines) and emerging technologies (fuel cells, micro-turbines, photovoltaics, wind energy systems, and storage technologies). Except for photovoltaic and wind energy systems of 10 kilowatts or less that are covered by Public Utilities Code Section 2827, the proposed Rule language applies to all other technologies. While not specifying any size limit, each system will likely be limited by generating capacity compared to the total load on the distribution feeder on which it would be located. Consequently, although no size or type limitations is placed on the applicability of Rule 21, the level of scrutiny a potential DG system may require during the interconnection review process may be related to the size of the system.

OIR Topic #3 (Development of Standards) and Topic #13 (Identification of Rule 21 Tariff Changes)

The working groups addressed the development of interconnection standards by using existing Rule 21 tariff language as a starting point. A description of each section of the revised Rule 21, along with a discussion of notable issues, is contained in Part III of this report.

As noted in Section 1.3 of the proposed Rule language, the Applicant will also be required to execute various enabling documents, such as a standardized Application and an Interconnection Agreement. The working groups are in the process of developing both documents are intended to report on progress at the April 25th hearing.

OIR Topic #4 (Safety Concerns)

Throughout the process, safety was a major theme echoed by many working group members. It was generally agreed upon that all interconnections need to be safe in terms of preventing damage to both the utility system and the DG unit, during normal and upset conditions, and in terms of preventing injury to utility personnel. Safety is discussed in general terms in Section 2, and is manifest in the specific technical design and operating requirements contained in Section 4, as well as in the test procedures described in Appendix B of the proposed Rule language.

The issue of worker safety, and more specifically the issue of whether minimum employee qualifications should be required for DG interconnections, was brought up verbally by the Office of Ratepayer Advocates (ORA) at the February 16, 2000 Energy Commission staff workshop. No formal written response by ORA was received until April 3, 2000, which was after the cutoff for the working groups to include written responses in their review. While no deliberations on the issue took place, ORA's suggestion for a workshop on safety issues is provided for future consideration, beyond the delivery date for a late June 2000 formal recommendation from the Energy Commission to the CPUC. Specific questions being considered include the following:

1. Are state licensing of workers and having/participating in a state-certified apprenticeship program required of entities or workers which install, operate, and maintain distributed generation facilities? If yes, are these requirements sufficient to ensure worker safety? If no, should they be required?
2. Do these programs and licensing standards differ from CalOSHA standards?
3. Should qualified employees from out-of-state, or uncertified programs, be grandfathered into certified apprenticeship programs and state licenses?
4. What agencies should inspect and enforce minimum employee qualifications?

OIR Topic #5 (Radial vs. Networked Distribution Systems)

The proposed Rule 21 language and initial review process apply mainly to DG connected to both radial and network systems. Since the majority of utility distribution systems are predominately radial[1] and because network systems are more complex, the screening subgroup was able to simplify the review process for radial systems. Future efforts will focus on development of a simpler review process for network systems, especially secondary network systems.

OIR Topic #6 (Need to Develop California Standards)

The working groups support the concept of developing California standards in parallel with the process coordinated by the Institute of Electrical and Electronic Engineers (IEEE) to develop national interconnection standards. The IEEE P1547 working group process has lasted for 16 months and is expected to produce a final draft by early 2001. The results of the workshop process in California will be presented to the IEEE effort at the April 26-27 meeting in Pittsburgh, Pennsylvania. Since many of the participants in the California workshop process are also involved in the IEEE effort, it is likely that IEEE will adopt much of the California technical approach. Two major limitations associated with the IEEE effort are the longer duration process and the fact that the IEEE P1547 working group only deals with technical standards (equivalent to Section 4 of the revised Rule 21.)

Members serving on both the technical working group in this proceeding and the IEEE P1547 working group process believe that California standards will be put in place and tested ahead of the IEEE effort. Additionally, certain elements of the proposed Rule 21, such as the initial review process and the testing/certification processes, will provide useful input to the IEEE national process.

In addition to coordinating these efforts with national work, several of California's publicly-owned utilities have been participating in the CPUC OIR process. CMUA has offered its assistance to disseminate proposed interconnection rules from this proceeding to the state's publicly-owned utilities.

OIR Topic #7 (Type Testing)

Type testing, or a common agreed-upon test procedure and performance criteria could greatly assist the proliferation of DG. Such testing and approvals, known as *Testing and Certification*, applied uniformly to standardized equipment, was considered by the working groups to be key to the rapid installation of DG. The technical working group, acknowledging that type testing is critical for streamlining and standardizing the interconnection process, created a subgroup to establish testing and

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1 Within SCE's and SDG&E's distribution systems, the distribution systems are almost exclusively radial in design. Likewise, the majority of PG&E's distribution system is based upon a radial circuit design. There are two network system exceptions, however, one in San Francisco and the other in Oakland.

certification criteria. Recommendations on a variety of type testing and limitations inherent in testing and certification are addressed in Section 4 and Appendix B of the proposed Rule language.

The working groups addressing type testing recognized that different types of DG technologies require different types of tests. Due to the emerging nature of distributed technologies and the novelty of applications, the working group recognized that it may not be possible to perform testing and certification for all technologies. Consequently, interim procedures are being developed for use until formal tests are developed, validated and the necessary infrastructure for administering tests is put in place. To the extent possible, testing procedures recommended by the technical working group are those that are applicable nationally and developed by IEEE or accredited testing laboratories.

OIR Topic #8 (Selection of Voltage Level)

In general, all parties agreed that the DG system must interconnect to the distribution system at the voltage level available at the area, and the responsibility for maintaining proper voltage levels is shared by both the *Electrical Corporation* and the *Electricity Producer*. The technical group and subgroups considered the impact of voltage level on screening, testing, and certification. The *Electricity Producer* may have to provide the added equipment necessary to accommodate the voltage level if the customer preferred voltage is different from the voltage of the connected distribution line. For the time being, however, the *Electrical Corporation's* current practices dictate the voltage level at which the DG systems can interconnect with the *Electrical Corporation* and also specifies the variance allowed in the voltage for the DG systems.

OIR Topic #9 (Government Agency/Utility Personnel Knowledge of DG)

Section 2 of the proposed Rule language describes the general rules, rights, and obligations of the *Electrical Corporation*. Section 3 describes the duties of the *Electrical Corporation* as they pertain to the entire application process, from initial contact by the DG developer through authorization of interconnection and reconciliation of payments.

Utility personnel will need to be properly informed and trained in order to carry out these functions; however, the scope of a utility's specific training procedures is beyond the scope of this working group process. In related work, however, the CPUC-led distribution planning and operations working group process is addressing the issues surrounding the planning and operational impacts of multiple DG units on distribution feeders. Finally, suggestions for performing outreach to state agencies and local governmental entities were to be included in the OIR Phase 1 testimony that was due on April 12, 2000.

OIR Topic #10 (Notification to UDC of "Islanded" DG)

In R.99-10-025, the CPUC defined an islanded system as one that is not interconnected to the distribution system. The CPUC asked that the Energy Commission address the issue of whether such an islanded generator should be required to notify the utility of the islanded distribution system. There are no safety or reliability reasons for such notification. However, existing tariffs address the issue of such notification relative to departing load charges when a utility customer uses such an island to supply loads that were previously served by the utility. Staff therefore recommends that no additional notification by the owner is required under the revised Rule 21.

It is worth noting that the utilities use the term *isolated generating facility* or *self-generator* to describe the type of generation mentioned as *islanded* in R.99-10-025. The term *islanding* is more commonly used to describe the condition when a generator supplies a part of the distribution system that is disconnected from the rest of the distribution system.

Extensive discussion ensued on *islanding* as the term is used by utilities. In the short term, *islanding* is considered to be the unintentional result when loss of utility power may inadvertently result in a DG feeding other utility customers. This should be prevented, because such *islanding* may have severe implications for the safety of the utility personnel and the integrity of the distribution system. This issue has been fully addressed by the groups and subgroups and adequate protections are being set in place.

In the longer term, it is envisioned by some that DG could be designed to create little islands of power, feeding local customers, thus minimizing the blackouts following a major catastrophe, such as an earthquake. Modern high-speed detection and communication technology could make this possible. Such *islanded* distribution systems could link together or run independently as necessary for maximum reliability. This larger issue becomes relevant only when DG is much more commonplace, and was therefore not considered in these workshops.

OIR Topic #11 (Need for Advanced Communications and Metering Equipment)

The potential impact of DG on utility grid reliability has raised the issue about privacy protection of information from distributed generators. Section 6 of the proposed Rule language addresses this issue, containing proposed requirements for metering, monitoring, and telemetry. It should be noted that certain aspects of the issue were debated extensively and have not yet resolved to this date. The ISO for example, has expressed certain needs related to metering and communication. Details surrounding the issues of controversy are contained in Part III of this report.

OIR Topic #12 (Variation in Standards by DG Type and Size)

From the beginning, the workshop participants followed the Committee's guiding principle that interconnection rules should be technology neutral with few exceptions. This means that no provision of the interconnection rule should discriminate against any of the potential DG technologies. However, interconnection standards development incorporates the engineering differences in generation technologies that use synchronous, and induction generation (combustion turbines, internal combustion engines, etc.) and those technologies that require conversion to the desired alternating current (photovoltaics, microturbines, fuel cells, etc.). These differences require different kinds of interconnection hardware to meet the safety, islanding and reliability issues. Consequently, there is some technology-based variation on the technical, screening, and testing provisions. One alternative of Section 6.4 of the proposed Rule language delineates the need for telemetering equipment based on DG nameplate rating. With the above exceptions, the proposed Rule language is technology neutral.

III. RULE 21 OVERVIEW AND DISCUSSION

This part of the report represents the focus of the working groups since the workshop groups began meeting in January. Rule 21 is currently part of each investor-owned utility's tariff booklet, applicable to connections with parallel generation units identified as *Qualifying Facilities*.[2] The group assumes that the language developed in this process will eventually replace the existing Rule 21 text.

Rule 21 in its proposed format contains eight sections and two appendices (see Table 2). The rule begins in Section 1 with a statement on applicability, followed by the general rules and obligations of both the DG customer and the utility (Section 2). The heart of the Rule is contained in Sections 3 and 4, which describe the non-technical and technical considerations for completing an interconnection agreement. Specific details on the screening and type testing procedures, both technical issues, is detailed in the two appendices. Ownership and operational considerations, as well as procedures for settling disputes, are addressed in Sections 5-7. The rule ends with a common set of definitions to ensure consistency in the rule language.

Table 2 **Rule 21 Sections**
1. Applicability and Introduction
2. General Rules, Rights, and Obligations
3. Application and Interconnection Process
4. Generating Facility Design and Operation Requirements
5. Interconnection Facility Ownership and Financing
6. Metering, Monitoring, and Telemetry
7. Dispute Resolution Process
8. Definitions of Terms
9. APPENDIX A – Initial Review Process
10. APPENDIX B –Testing and Certification

The remainder of this part describes the intent of each Rule 21 section, followed by a discussion of issues of concern addressed by the working groups in the development of the rule language. Each section concludes with a staff recommendation. The major subtopics of the rule language are shown in italics.

The specific target language and compilation of stakeholder comments on each section of the proposed Rule can be found in Appendix A of this report. The target language, identified in boldface, represents a *majority opinion* about the preferred text for the Committee to consider. It does not, however, suggest that alternative opinions should not be given consideration. Opinions different from the majority

[2] A *Qualifying Facility* is defined to be a Generating Facility meeting the criteria for a QF defined under the Code of Federal Regulations, Title 18, Chapter 1, Section 292, Subpart B of the Federal Energy Regulatory Commission's regulations.

opinions are provided in each section below the target language. **These sections are important to the evaluation process as it memorializes issues that were raised by parties during the working group process but not incorporated into the target Rule 21 language.** Equally important, it gives the Committee the opportunity to further consider alternatives as it develops its full recommendation to the CPUC.

Section 1 – Applicability and Introduction

1.1 Applicability
1.2 Definitions
1.3 Enabling Documents

The main objective of this section is to generally identify parties that are subject to Rule 21. In the context of the OIR, the rule as proposed in this workshop process applies to all *Generating Facilities* that seek to interconnect with an electricity distribution system subject to CPUC jurisdiction. While the CPUC does not have jurisdiction over municipalities and irrigation districts, several municipality representatives have participated in this process, recognizing the importance of developing a statewide standard applicable to all electrical corporations in California.

In much the same way that jurisdiction has been conferred on the CPUC over California's investor-owned utilities, respective boards and councils have been provided general authority under the California Constitution and Public Utilities Code to establish policy for publicly-owned utilities, and to provide for their regulation. This dual regulatory framework was reaffirmed in Assembly Bill 1890 (Statutes of 1996, Chapter 854), where key restructuring decisions were left to the local regulatory bodies of publicly owned utilities. With regard to interconnection rules for distributed generation, neither the CPUC nor the Energy Commission has jurisdiction over publicly-owned utilities. However, publicly-owned utilities have previously collaborated with the CPUC, the Energy Commission and the investor-owned utilities in the development of standards and rules, and publicly-owned utilities routinely look to standards set by the CPUC for guidance in establishing their own standards.

To provide an indication about the commitment of publicly-owned utilities to the deployment of DG and the interconnection of these resources with their electric systems, we offer the following example. California's two largest publicly-owned utilities, LADWP and SMUD, have developed renowned programs for the deployment of solar photovoltaic systems. Publicly-owned utilities have also participated in the advancement of other distributed generators, including fuel cells and advanced microturbines. Relative to customer-owned distributed generation, various publicly-owned utilities have provided for interconnection by adopting rules and agreements that allow generators to be connected for parallel operation with the distribution system.

<u>Working Group Concerns About Section 1</u>

Being the introductory section of the Rule language, there were no notable concerns to report from this section. The major area of discussion centered on the language of Section 1.3 and whether the Interconnection Application or Interconnection Agreement should be included in the Rule language. In the interest of maintaining flexibility, the working group proposes that the agreements be referenced in the language as documents being on file with the CPUC, "as amended from time to time."

Staff Recommendation

Staff recommends the Committee endorse the definition language contained in Section 1.

Section 2 – General Rules, Rights, and Obligations

2.1 Authorization Required to Interconnect
2.2 Separate Arrangements Required for Other Services
2.3 Transmission Service Not Provided with Interconnection
2.4 Compliance with Laws, Rules, and Tariffs
2.5 Design Reviews and Inspections
2.6 Right to Access
2.7 Confidentiality of Information
2.8 Prudent Operation and Maintenance Required
2.9 Protection of Producer's Facilities
2.10 Curtailment and Disconnection

This section provides the general rules applicable not only to the interconnection application process but also procedures associated with the design, safe operation, curtailment, and disconnection provisions of the interconnection. It begins by explaining the need for an *Electric Producer* to comply with Rule 21, followed by the requirement for having the utility provide written authorization before the interconnection can become operational. After stating that other distribution and transmission-related utility services require separate agreements, the section addresses the need to comply with appropriate CPUC-approved tariff rules and regulations, and comply with appropriate local, state, federal, statutes or regulations. Access rights to the *Electric Producers'* facility and data confidentiality issues are then addressed as well as the need to ensure that the utility system is not compromised because of the interconnection. The section ends with a discussion of provisions required for disconnection or curtailment.

Working Group Concerns About Section 2

The principles surrounding the development of Section 2 were generally accepted by the working group members. Still, parties raised several concerns were raised with respect to Sections 2.4, 2.7, and 2.10. Each is described below.

Regarding Section 2.4 (Compliance with Laws, Rules, and Tariffs), the ISO argues that its name should be specifically recognized in the Rule language. Most parties felt otherwise, arguing that no other entity is specifically noted in the language.

The groups also expressed some concern about data confidentiality (Section 2.7). As presently written, the proposed Rule explains that the "*Electrical Corporation* shall not use or disclose information provided by an Applicant to propose competing *Generating Facility* installations to the Applicant." Enron believes that the *Electrical Corporation* should not be allowed to disclose that information to anyone outside of its own company. Honeywell maintains this restriction does not go far enough, claiming it is possible for a utility to use the knowledge of an interconnection application to propose discounted rate alternatives to the customer. Honeywell acknowledged that any customer could approach the utility to seek discounted rates, and that the utility is authorized to offer discounted rates. The timing of the request for interconnection provides competitive information that could be used to interfere with the business relationship between the customer and the DG service provider. Coast Intelligen seeks to ensure that affiliates are not provided this information in the event the affiliate rules currently in place do not extend to interconnection issues.

One final issue surrounds Section 2.10 (Curtailment and Disconnection). Hetch Hetchy noted that incremental demand charges during curtailment periods not be assessed to the *Electricity Producer* being interconnected.

Staff Recommendation

Staff recommends that the Committee endorse the rule language applicable to all portions of Section 2 with the exception of 2.4, 2.7, and 2.10. The Committee should entertain additional discussion at the April 25th hearing on data confidentiality and curtailment/disconnection issues and specifically have parties address their concerns in written comments.

Staff notes that the Energy Commission has previously urged positions like that endorsed by Enron in Section 2.7, but the CPUC has not accepted them. For example, in the advice letter protest process for the new UDC load curtailment programs authorized by the CPUC on April 6, 2000, the Energy Commission proposed that information about participants in load curtailment programs not be shared among other units of the UDC beyond the direct program staff. The CPUC did not act on this request. The concern expressed by Enron and others reflects the ambiguity of the role of the UDC, which currently encompasses numerous functions. As long as the UDC is permitted to simultaneously engage in both regulated monopoly and competitive market activities, some market participants will be concerned that knowledge gained for legitimate purposes in furtherance of the distribution function will be used for anti-competitive purposes. Staff suggests this topic be addressed further during the April 25th hearing.

Section 3 – Application and Interconnection Process

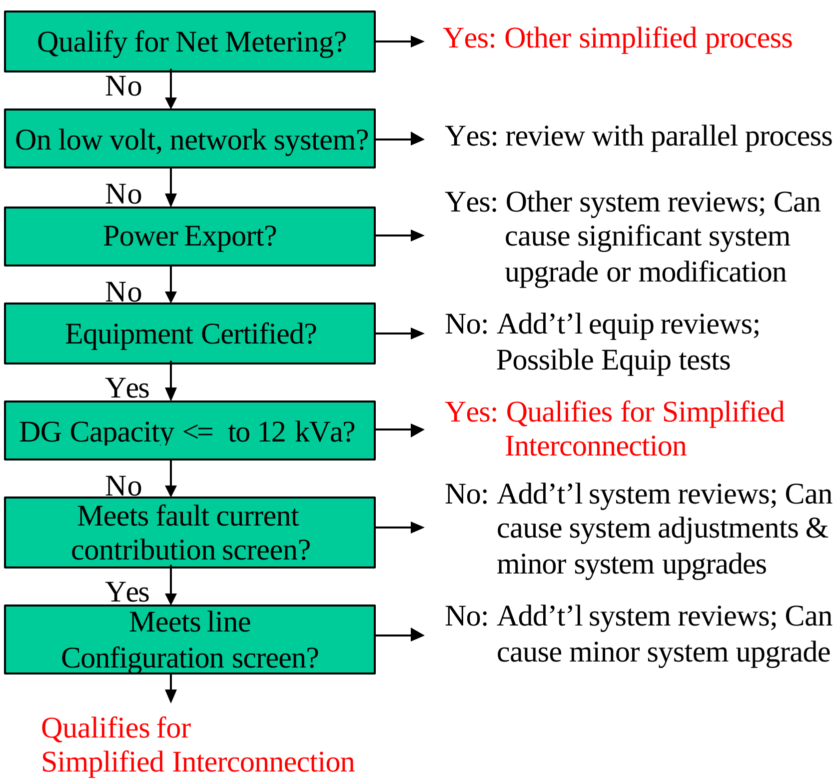
3.1 Application Process
3.1.1 Applicant Initiates Contact with the Electrical Corporation
3.1.2 Applicant Completes an Application Document
3.1.3 Electrical Corporation Performs an Initial Review and Develops Preliminary Cost Estimates and Interconnection Requirements
3.1.4 When Required, Applicant and Electrical Corporation Commit to Additional Interconnection Study
3.1.5 Applicant and Electrical Corporation Enter into a Generation Interconnection Agreement, and, Where Required, a Financing and Ownership Agreement for Interconnection Facilities or Electric System Modifications

3.1.6 Electricity Producer Installs or Constructs the Generating Facility; Where Applicable, Electrical Corporation or Electricity Producer Installs Required Interconnection Facilities or Modifies Electric Corporation's Electric System
3.1.7 Electricity Producer Arranges for and Completes Testing of Generating Facility and, Where Applicable, Electricity Producer Installs Interconnection Facilities
3.1.8 Electrical Corporation Authorizes Interconnection
3.1.9 Electrical Corporation Reconciles Costs and Payments

Section 3 details the steps necessary for a DG applicant to connect to an *Electrical Corporation*. The process begins with the DG applicant making an initial inquiry about connecting to the distribution system. The *Electrical Corporation* shall then provide the Applicant with a standardized application and associated technical documents within three business days. The Applicant then files a completed application with the *Electrical Corporation* along with a fee for processing the request and performing an initial review of the application.

The key to the application review is an *Initial Review Process* developed by the technical working group. Its primary purpose is to allow the *Electrical Corporation* to distinguish the review for applications that can quickly be approved from those that need a more significant commitment of resources from the *Electrical Corporation*. The review for applications is categorized into three groups: 1) a simplified review, 2) a supplemental review that may require minor system modifications, and 3) a supplemental review that requires an major interconnection study with significant system changes. Figure 1 illustrates the flow of information for the *Initial Review Process*.

Figure 1 – Initial Review Process



Provided courtesy of David Townley, New Energy

To qualify for the simplified review, an Applicant's proposed DG interconnection must pass a series of basic interconnection questions and threshold parameters. The parameters applicable to the simplified review are considered very conservative by the technical group and are intended to be applicable regardless of where the DG interconnection is located on the distribution system. However, an application can still be screened on a simplified basis if the reviewer determines that the threshold parameters of the screens are exceeded without compromising the protective "intent" of those screens.

For an application not passing the initial screens, a more in-depth review is required to identify minor system modifications and identify items specifically required of the Applicant, that will be needed before the interconnection is completed. For applications determined by the reviewer to require significant modification to the distribution system at the desired location, the Applicant and *Electrical Corporation* shall formally agree to the terms and conditions of an interconnection study prior to connection.

The Applicant can construct the interconnection facilities and commence operation upon compliance with the provisions of any required documentation, signing an interconnection agreement, paying all applicable fees, and satisfactorily completing any required inspections or tests.

<u>Working Group Concerns About Section 3</u>

Four concerns stemmed from the Section 3 discussion. The first relates to timing behind the *Initial Review Process* work completed in Section 4 and its need to be incorporated into Section 3. That discussion will be addressed in the section noting concerns about Section 4.

Second, some parties have expressed concern about the firmness of the days required to complete various portion of the initial and supplemental review. The proposed Rule language refers to an *Initial Review* that will not exceed 10 days, and a *Supplemental Review* with minor modifications that does not add more than another 10 days to the review process. Both PG&E and SDG&E have voiced concerns about the time limits. SDG&E in particular does not support specific time limits but endorses language that offers a best-efforts attempt to complete the review process within a certain timeframe.

The third controversial discussion focused on the interconnection application and the calculation of the interconnection study costs. Working group members noted that present interconnection study costs are traditionally treated as a "black box" of information. In these situations, the utility is not required to detail the costs of specific tasks performed in the study; rather, the Applicant is simply provided a bill for the study with no explanation. PG&E, in response to this claim states that it would provide a cost breakout upon request. One goal of this section was to provide some certainty for study costs.

Expanding on that issue, DG vendors were concerned about the mechanism for recovering the interconnection costs. The group believes that the *Electrical Corporations* should expect to recover these costs. The application and initial review costs could reasonably be recovered by way of an up-front fee. However, additional costs could arise from asset purchases such as line upgrades or transformers which are at the core of the utility's business. There are a number of mechanisms whereby these additional costs could be recovered including:

1. An up-front charge to the DG customer that corresponds directly to the costs of interconnecting their particular installation. This approach minimizes the financial risk to the utility.
2. An additional charge incorporated into general rates. This becomes an issue of rate equity between customers with and without generation. It could be based on criteria applicable to both types of customers. This approach may be appropriate if the system wide benefits of distributed generation are sufficient.
3. A general interconnection fee (e.g., fixed monthly dollar amount or dollar per installed kilowatt) charged monthly to each DG customer.
4. A monthly interconnection fee that may vary by location or generator that reflects the benefits (e.g. any avoided capital cost) as well as the costs of the DG customer to particular locations. This approach can be used to encourage distributed generation in areas where there are capacity constraints.

Finally, the ISO stated its belief that it should be notified when an application is submitted and when an interconnection is completed. It argues that the information would be useful in the context of system planning. Many of the working group members questioned why the ISO needed information on all interconnection applications submitted, including those that do not result in an interconnection.

The non-technical working group did not have time to identify the range of alternatives for identifying interconnection costs and has not been able to begin to assess the advantages and disadvantages of each. The rate design aspects of this issue will be addressed in Phase 2 testimony of the CPUC OIR, providing an appropriate forum for evaluating alternative methods of recovering interconnection costs. The CPUC should look to the rate design proceeding for guidance on the issue of cost recovery and adopt Rule 21 language that accommodates the conclusions of the rate design discussion in the OIR.

Staff Recommendation

Staff recommends Committee endorsement of the *Initial Review Process* and the proposed Rule language that supports the concept. The initial review process has been thoroughly discussed in both the technical and non-technical working groups; hence changes made since the completion of the workshop process are mostly cosmetic. **The *Initial Review Process* is the key change to the Rule 21 language currently applicable to each of the three investor-owned utilities and is strongly supported in concept by the working groups.**

Section 4 – Generating Facility Design and Operating Requirements

4.1 Purpose
4.2 General Interconnection and Protection Requirements
4.3 Prevention of Interference
4.4 Control, Protection, and Safety Equipment Requirements for Distributed Generators

This section provides the technical (electrical engineering) underpinnings for the procedures and practices of interconnection recommended in Rule 21. The section identifies the basic electrical engineering issues affecting the safety and reliability of the distribution grid. In addition, it specifies performance requirements (rather than equipment) and operating conditions that must be met to safeguard the distribution grid against power quality and other disturbances that might originate in a DG system. The specifications in the proposed Rule language are based on current utility practices and the National Electrical Codes. The section also reflects general agreement on certification and testing protocols that would be acceptable to *Electrical Corporations* and ultimately expedite and simplify the interconnection process. The recommended certification and testing, to the extent possible, references the work in progress of the various IEEE committees currently addressing interconnection issues on a national level. Some of the distribution technologies and the interconnection equipment are still evolving, and the testing protocols are still being developed. This section recognizes this limitation and recommends an interim solution that is generally acceptable to the concerned parties. It also addresses the technical aspects of the screening process that allow for expedited interconnection application review. The detailed steps involved in the screening process are presented in Appendix A of the proposed Rule language.

This section was developed by a technical subgroup of the interconnection working group and mostly consisted of electrical engineering professionals representing the utilities, vendors, system integrators and consultants working for the Energy Commission. As indicated earlier, several participants are presently serving on national IEEE committees formulating national interconnection standards and testing protocols. The extensive work done by this group through this workshop process far surpasses work on interconnection rules completed in other states; as a result, California standards that develop out of this investigation could affect the development of national interconnection standards.

Given the evolving nature of distributed generation technologies, Section 4 remains a *work in progress*. As the equipment and performance related issues surface, this section will be periodically updated, primarily by revising the provisions described in Appendix B of the proposed Rule language.

<u>Working Group Concerns About Section 4</u>

The heart of the technical discussion focused on the screening process. Parties were generally comfortable with the direction of the screening process but voiced concerns about the need to extend the screening process discussions well beyond the Committee-imposed March 31 cutoff date for a working group submittal to staff. In the course of the working group meetings, staff agreed to let technical discussions continue through April 14. The results of those additional two weeks, while incorporated in the proposed Rule language and discussed in this section, were not fully debated by the non-technical group.

Staff Recommendation

In the absence of receiving input from the non-technical group, staff recommends the Committee specifically request that parties address the content of Section 4 in comments that are due on May 2nd. Those comments should include a section voicing concerns about specific areas of the section language. Based on the written materials that are submitted, the Committee may wish to hold a separate hearing to further consider the rule language. Alternatively, if it is clear at the hearing that parties generally favor the tone and content of Section 4, then staff recommends the Committee endorse the language soon after reviewing written comments from stakeholders.

Section 5 – Interconnection Facility Ownership and Financing

5.1 Scope and Ownership of Interconnection Facilities
5.2 Responsibility for Costs of Interconnecting a Generating Facility
5.3 Installation and Financing of Interconnection Facilities Owned and Operated by Electrical Corporation

This section deals with the cost allocation of DG interconnection. The policy issues for cost allocation of DG interconnection are part of the rate design discussions and testimony in Phase 2 of the CPUC's proceeding on distributed generation. Because of this fact and the timing of the proceedings versus this effort to revise Rule 21, **the language within this section reflects how the cost allocation is currently instituted and does not prejudge how the CPUC should determine this matter.** The section as written provides a method of cost allocation during the interim period between when the proposed Rule language is adopted and when the CPUC addresses cost allocation questions. Following a CPUC decision regarding cost allocation and rate design structure, Section 5 will need to be reviewed and revised for consistency, as necessary.

Some specific issues that may be determined by the CPUC to be treated in a manner different than is described within this section include, but are not limited to:

- Utility ownership of interconnection facilities on the customer side of the *Point of Common Coupling*;
- Customer or third-party ownership of interconnection facilities on the utility side of the *Point of Common Coupling*;
- Cost allocation equity and consistency between what is done for/with customers without DG and those with DG;
- Cost allocation and/or ownership rights regarding system additions or modifications that create excess distribution capacity for the benefit of others, including
  - Future load customers;
  - Future DG customers, including provisions per line extension rules for rebates from future exporting DG customers;
- Fee treatment of the interconnection review and interconnection studies; and

- Ownership and control of interconnection study results for a specific DG application.

Working Group Concerns About Section 5

No specific concerns were raised with respect to this section, although some concern was expressed about who bears the costs for system modifications.

Staff Recommendation

The language contained in Section 5 of the proposed Rule should be fully endorsed by the Committee. The issue of cost allocation is a rate design issue that is more appropriate to address in the Phase 2 testimony of the CPUC rulemaking.

Section 6 – Metering, Monitoring, and Telemetry

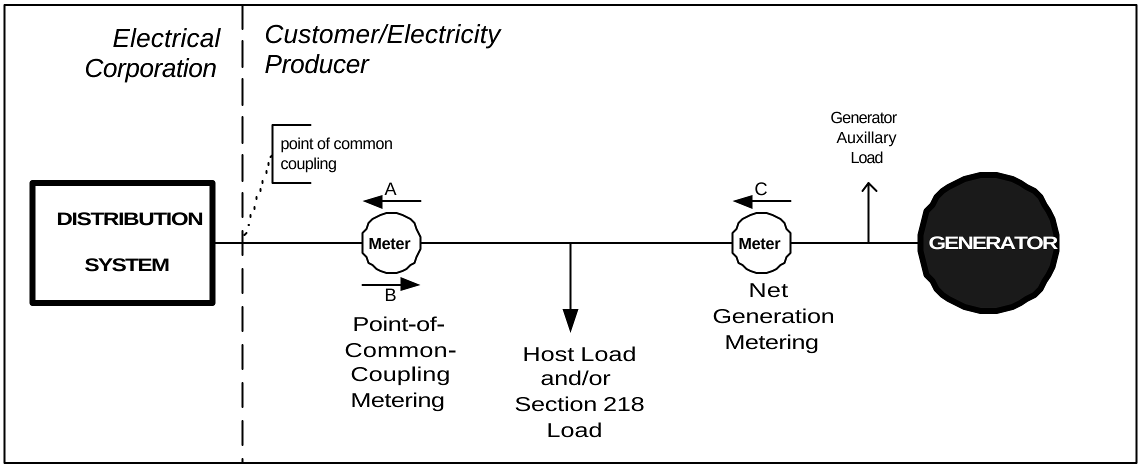
6.1 General Requirements
6.2 Metering by Non-Electrical Corporation Parties
6.3 Alternative 1: Net Generation Metering
6.3 Alternative 2: Point of Common Coupling Metering
6.4 Telemetering
6.5 Location
6.6 Costs of Metering

This section responds to the need for requiring advanced metering equipment in order to efficiently schedule and dispatch DG. It begins with the general requirement that all *Generating Facilities* shall comply with all applicable tariffs and *Electrical Corporation* manuals dealing with metering specifications. The section does not apply to *Generating Facilities* operating with net metering tariffs.

The proposed Rule language then identifies that meter ownership, installation, operation, reading, and testing shall be performed by the *Electrical Corporation* except when the CPUC authorized another entity to perform the task. The section also addresses meter location issues, such as placement of the meter, and proposes that the *Electricity Producer* and/or customers bear all of the costs required by Rule 21.

The remainder of the section deals with specific areas that were discussed extensively and bear further elaboration. The concept of *net generation metering* was addressed to ensure that the terminology used by the working groups was consistent. As shown in Figure 2, *net generation metering* occurs at the point after auxiliary load (electrical load required to run the generator). The ISO characterizes the same term as *gross generation metering* while the net generation concept is used in the field.

FIGURE 2: METERING DEFINITIONS



Provided courtesy of Dylan Savidge, PG&E

"A" is a measure of power flow from the Customer's Generator to the Distribution System. This power flow is "net" of Generator Auxiliary, Host and Section 218 Loads.

"B" is a measure of power flow from the Distribution System to the Customer Host Load and/or Generator Auxiliary Load (provided if load exceeds local generation or at times when the generator is not operating).

"C" is Net Generation Metering, a measure of the net Generator output; after Generator Auxiliary Loads are served.

Generator Auxiliary Loads are only those loads associated with the operation of the Generator for its startup and continued operation.

Host Load is defined in the Glossary section of Rule 21 as electrical power that is consumed by the Customer at the property on which the Generating Facility is located. Host load that is served by the Electrical Corporation is measured at the Point of Common Coupling

Section 218 Load is load that is served "over-the-fence" to a neighbor without using the distribution system. Public Utilities Code defines conditions under which such an "over-the-fence" transaction would not classify the *Electricity Producer* performing an over-the-fence sale as an *Electrical Corporation*.

Net Metering is defined as the difference between "A" and "B" over a given time frame (such as a year for PG&E E-NEM accounts). This difference is then billed (if the difference yields a net consumption by the Customer) at a given rate.

Working Group Concerns About Section 6

The major issue of disagreement during the discussion of Section 6 concerned whether net generation metering should be required for *Generating Facilities*. Net generation metering is currently required for most DG interconnections[3] per distribution company tariffs and metering guidelines published in current interconnection handbooks. The requirement is needed for: 1) qualifying cogeneration gas

[3] With the exception of those qualified under Public Utilities Code Section 2827.

allocations, 2) standby service administration, and 3) power purchase agreement administration/monitoring. Metering at the *Point of Common Coupling* is also required to measure power flow out to the distribution system as well as power supplied by the distribution system into the DG Customer's facility.

The utilities and the ISO hold the position that net generation metering is required. From a distribution system planning and operations framework, they believe that information on net generation output is required to ensure the safe and reliable operation of the distribution system.

For ratemaking, the utilities argue that accurate non-bypassible and standby charge calculations can only be accomplished with revenue-quality, metered data. For cogeneration activities generation output is used to determine a monthly heat rate to determine the amount of gas that qualifies each month for a cogeneration gas rate. Finally, data reporting to regulatory bodies is simplified by having net generation metering required.

The other working group members do not universally accept the utility and ISO position. Honeywell, for example, does not believe that separate measurement of generator output is necessary or should be required. Other parties have voiced similar concerns. The Cogeneration Association of California/Energy Producers and Users Coalition's (CAC/EPUC) principal concerns with respect to the proposed Section 6 language fall into three categories: 1) excessive metering costs may deter or eliminate the growth of distributed generation in California, especially smaller projects; 2) intrusive metering requirements may expose a distributed generator's confidential commercial information to third parties; and 3) parties lacking jurisdiction or any other right to metering information (and/or any other regulatory right to monitor or exercise operational control over distributed generation) may attempt to boot-strap such authority onto the UDC's metering authority.

CAC/EPUC is also concerned with the vagueness surrounding the "type" of metering sought by the utilities. At the workshops it was indicated that "revenue quality" meters would be required. Without precisely knowing what type of meters and the scope and type of information the UDCs seek to collect, the natural concern is that the maximum amount of information, utilizing the most expensive metering equipment, is what is sought. Currently, there is no requirement for revenue quality net generation metering.

CAC/EPUC supports several broad policy guidelines to determine what metering should be required, if any: 1) the UDC should clearly articulate the reason or purpose for which it requires such data and the minimum amount of data required to accomplish this purpose. 2) the least expensive method, including non-meter methods where applicable, should be selected unless the distributed generator in its sole discretion chooses otherwise; and 3) where the UDC's purpose may be accomplished by only metering a subset of distributed generators, the metering requirement should not be applied to all distributed generators.[4] CAC/EPUC prefers moving non-uniform metering requirements out of Rule 21 and into

[4] For example, a) metering small projects may only yield data "noise" that will not assist the UDC in system planning and operations; b) metering required for departed load calculations should not be applied to generators which do not fit the definition of departed load; c) where a distributed generator has either

applicable agreement or tariffs (a stand-by tariff, capacity contract, etc.). Finally, any information gathered is the propriety information of the distributed generator and should only be released to a party other than the UDC with the express consent of the distributed generator.

Other issues raised in the working group meetings but not resolved were data confidentiality and data used to separate generation from load for ISO Grid Management charges.

Staff Recommendation

Staff recommends that the Committee endorse the rule language applicable to Sections 6.1,.6.2, 6.5, 6.6, and 6.7.

While not the most significant issue in the proposed Rule, this section presents an area where mutual agreement on Sections 6.3 and 6.4 of the proposed Rule language was not possible. As such, Sections 6.3 and 6.4 contain two sets of proposed language for that section. Specific time at the April 25th hearing will be placed on the agenda to debate the issue in front of the Committee.

What is evident from this discussion is that the workshop process could not fully address the multitude of technical and policy issues related to metering. Parties on both sides of the issue have argued for a formal extension of time to resolve differences, in light of the significant momentum achieved by the parties. As such, staff recommends that the Committee recommend further deliberation during May that could potentially be incorporated into the Committee's formal recommendation to the full Commission. To the extent that time is not adequate, the formal recommendation to the CPUC should include a timetable for resolving the issue here using the current Energy Commission OII.

Section 7 – Dispute Resolution Process

Rule 21 language contained in Section 7 refers to the process required to resolve interconnection issues under dispute. Under the proposal, disputing parties have 45 calendar days to meet and confer to try and resolve a dispute. If the dispute is not resolved during that period, the CPUC would address the issue using current dispute guidelines pursuant to Article 3 (Rules 9-14) of the CPUC Rules of Practice and Procedure. Pending resolution of any disputes, the proposed language calls for the *Electrical Corporation* and the *Electricity Producer* to continue with the performance of their respective obligations under the interconnection agreement.

declined stand-by service or opted for a non-variable stand-by service, metering requirements necessary for variable requirements stand-by service should not apply; d) metering required for purpose of receiving cogeneration gas tariff rates should not be applied to distributed generators not taking service under this tariff; and e) metering required for distributed generators who participate in the ancillary markets and/or have contracted with the UDC to provide capacity or voltage support should not be required of non-exporting or non-participating generators.

Working Group Concerns About Section 7

The working groups voiced two concerns about the content of Section 7. Some believe that the dispute process is invariably skewed in favor of the utility. If, for example, the utility seeks to extend the arbitration process for a significant length of time, a non-utility disputing party might not have the resources left to continue the resolution process. In that case, the utility wins the dispute. Alternatively, if the party wants to continue the process, it occurs in a CPUC forum.

The other concern was voiced by PG&E, claiming that the proposed language has not been fully debated by the group. This lack of debate is the result of a focus on other issues relevant to the workshop process.

Staff Recommendation

Staff believes that additional work is needed to further refine the dispute language. While the concerns noted by parties are quite valid and deserving of consideration, staff believes that the proposed language is appropriate for the Committee to endorse. Recognition should be given that additional work should be done in this subject area after interim Rule language is adopted by the CPUC.

Section 8 – Definitions

The final section of the proposed Rule language is designed to ensure consistency across all sections of the proposed Rule language. A definitions subgroup was empowered to develop specific definitions covering a wide range of technical and non-technical terms. More than 50 definitions were developed and are provided in Section 8 of the proposed Rule. Both working groups offered general agreement on the list of definitions.

Working Group Concerns About Section 8

Beyond calls for minor improvements to definition language, no major concerns were voiced by the working groups.

Staff Recommendation

Staff recommends the Committee endorse the definition language contained in Section 8.

IV. OTHER ISSUES OF CONCERN

Part IV is designed to address areas of concern that do not necessarily apply to specific sections of the proposed Rule 21 tariff language. The theme of the concerns focus on a process for expeditiously modifying Rule language in the future, as well as key interconnection documents that are not part of the formal Rule. Staff does not suggest that the concerns represented in Part III combined with the concerns addressed in this part of the report represent the entire spectrum of issues in this workshop process. For further review of issues raised, staff refers the Committee to the comments of each section expressed in Attachment A.

Standard Application and Interconnection Agreements

The concept of a standard application and interconnection agreement was first addressed by the working groups as an intended product of the workshop process. As the group focused on proposed Rule language, it became clear that the agreement development would need to rely on the direction of the proposed Rule language before work could proceed on that issue. The group also agreed to build Rule language that referenced agreements rather than including samples in the Rule language.

A major effort to draft standard application and interconnection agreements began near the conclusion of the formal workshop process. Meetings were held by interested members of the working group through April 14th to develop a proposal for the Committee to consider. The sample application and interconnection agreements resulting from those meetings are provided in Attachment B of this report. The attached agreement is proposed to be the first of what is envisioned to be a family of standardized agreements used to implement the changes proposed for Rule 21. It is designed for what is expected to be the most common use of distributed generation, a generator installed at a utility customer's facility. It does not provide for the sale or export of power to the utility, nor for the benefits afforded under Section 2827 of the Public Utilities Code regarding "Net Energy Metering." Other standardized agreements are expected to be developed and used to accommodate such arrangements.

While several of the sections in this agreement appear to be acceptable to most of parties in this effort, our group was unable to reach consensus on a few key elements of the document. The most significant and problematic areas of disagreement include the provisions for liability and insurance coverage. Other unresolved issues include how to address demand charges which may be incurred by a customer who consumes energy during a period when it has been forced to curtail or interrupt its generation, and a party's right to schedule or control the maintenance outages taken by the other party. These issues will be further addressed at the April 25th hearing.

Lack of Balanced Representation in Working Groups

As mentioned in Part I of this report, approximately 75 people participated in the working group process. The group reflected a wide range of interests from utility representatives, DG manufacturers, DG customers, regulators, marketers, and small end-use customer groups. Notwithstanding the range of representatives, the extent to which some groups could actively participate raised some concern about whether the workshop process was favorably skewed in the direction of utility positions.

At each meeting, utilities were well represented in both the technical and non-technical working groups. Some utility individuals in fact played key roles in the development of the proposed Rule language. In contrast, many stakeholders representing "small scale" companies for both generators and consumers did not have the resources available to be represented at each of the working group meetings.

In staff's opinion, this dilemma is common to all types of regulatory proceedings, not just this proceeding. In the case of CPUC proceedings or proceedings supporting a CPUC work effort, utilities by definition are going to be well represented since they are under CPUC jurisdiction. Individual stakeholders are inherently disadvantaged in terms of being able to actively attend all meetings.

In spite of this perceived disadvantage, the working group process has appeared to proceed with a free exchange of information between all parties. Staff believes that any skewing of issues in favor of utility positions has been minimal.

Forum for Addressing Additional Work Needed to Proposed Rule Language

By no means is the proposed Rule 21 language contained in the report 100 percent complete. Throughout the working group process, parties have suggested that, while much discussion has produced significant progress in the development of new Rule 21 language, additional work is needed in various areas. For example, clear differences with respect to telemetering requirements (Section 6) require further deliberation that may or may not be completed before a final recommendation is sent by the Energy Commission to the CPUC. In Section 7, the dispute resolution language relies heavily on existing dispute processes at the CPUC and therefore needs additional debate. Notwithstanding the additional work that is needed, the Committee will still be in a position to provide a complete set of recommendations to the CPUC for further consideration. The key to doing so is to design a process that retains status quo rule language in lieu of further discussion on the issue. At the April 25th hearing, the Committee must determine which issues it would like further deliberation and the timeframe for completing that work.

Forum for Addressing Future Changes Once the Proposed Rule is Adopted

During the course of the workshop process, the non-technical working group identified a need to develop a procedure to address future changes to the Rule language once the rules are adopted by the

CPUC. One suggestion made was the possibility of establishing regular meetings of the interconnection working groups to address issues that need further refinement to allow the markets to better function.

CPUC Decision 97-10-087 contains language related to the creation of the Rule 22 (Direct Access) Tariff Review Group and bears repeating here for further consideration:

> …a working group should be established to review the direct access tariffs and other tariffs and rate schedules that are affected by the direct access tariffs. We envision this working group to be made up of market participants who have the common goal of ensuring that direct access succeeds. The working group is in a position to see how the adopted direct access tariff provisions are working, and to make recommendations as to how the tariffs should be changed. This working group process will provide us with an opportunity to fine-tune the direct access tariffs, and to eventually have all the UDCs in this state using a uniform direct access tariff. (CPUC Decision 97-10-087, pg. 69-70).

This concept has some potential application to how issues related to Rule 21 could be addressed in the future. Staff recommends that the Energy Commission open a new proceeding specifically designed to allow the current interconnection working groups to meet on a regular basis to address issues and propose changes. Working group activity could continue to be facilitated by Energy Commission staff, with results reported to the Committee as necessary.

At the same time, the CPUC would need to provide an expedited process for approving utility advice letter filings related to changes in Rule 21 tariff language. In developing its formal recommendation for Energy Commission consideration, the Committee should request parties file proposals to that affect.

Extending CPUC Rules to Municipalities and Irrigation Districts

Representatives from several publicly-owned utilities have actively participated in the interconnection working group meetings from the outset of the workshop process. Many have suggested the possibility that rules adopted by the CPUC could be tailored to apply to their respective municipality or irrigation district. Recognizing the value of this process to entities outside the jurisdiction of the CPUC, CMUA has indicated a willingness to assist the Energy Commission in disseminating the recommended interconnection rules to the various publicly-owned utilities. The recommended interconnection rules could be presented for review and eventual consideration by the respective local regulatory bodies.

Monitoring the Development of Distributed Generation

As the workshops progressed, participants from different stakeholder groups expressed uncertainties about the potential impact that DG could create. It was broadly felt that there would be significant benefits to monitoring the first several DG projects implemented under the revised rule to see how the intent of the new rule language matches expectations. While several of the new DG and interconnection technologies show promise for cost reduction, they are often not fully tested or fully understood. A program of monitoring, training, and closing the gap between electricity producer desires and utility concerns for the first several DG systems could go far towards resolving many of the utility concerns, and thereby remove a barrier slowing the proliferation of DG.

From a data collection standpoint, data associated with DG interconnections are important to the Energy Commission. In November 1999, the Energy Commission adopted a policy report entitled ***Report on Generator & Consumer Data Reporting Requirements,*** directing staff, among other things, to prepare appropriate data collection regulations to obtain generator output and fuel use data from all generators. A key provision of this policy decision is obtaining the "interconnection database" from each UDC that would be used as the "universe" of all generating facilities interconnected to the UDC distribution system.

This database serves two purposes. First, successive annual editions of this database would enable analysis of generation technology installation trends required of the Energy Commission by Public Utilities Code Section 383 and other statutory directives concerning renewable generation technologies. Second, this database provides a source of generator ownership and contact information that can be used to ensure that all generators are complying with Energy Commission data reporting requirements. Staff recommends that Section 6 of the proposed Rule language specifically note that the UDC is to develop and forward to the Energy Commission such an interconnection database. Staff recommends that appropriate language be developed by the working groups over the next month and included in the final language recommended by the Committee to the Energy Commission.

V. STAFF RECOMMENDATIONS

Staff generally supports the recommendations of the working groups based upon the guiding principles set forth by the Committee. The recommendations are based upon the agreements achieved by the majority of the working group members while also respecting the alternative views of the participants. For additional insight into the alternative views, the report notes those areas of contention as well as those areas of substantial agreement.

With respect to proposed Rule 21 language, staff's specific recommendations to the Committee are summarized below.

Section 1: Staff recommends the Committee endorse the definition language contained in Section 8.

Section 2: Staff recommends that the Committee endorse the rule language applicable to all portions of Section 2 with the exception of Sections 2.4, 2.7, and 2.10. The Committee should entertain additional discussion at the April 25th hearing on data confidentiality and curtailment/disconnection issues and specifically have parties address their concerns in written comments.

Section 3: Staff recommends Committee endorsement of the *Initial Review Process* and the Rule language that supports the concept. The *Initial Review Process* has been thoroughly discussed in both the technical and non-technical working groups; hence changes made since the completion of the workshop process are mostly cosmetic. **The *Initial Review Process* is the key change to the Rule 21 language currently applicable to each of the three investor-owned utilities and is strongly supported in concept by the working groups.**

Section 4: In the absence of receiving input from the non-technical group, staff recommends the Committee specifically request that parties address the content of Section 4 in comments that are due on May 2nd. Those comments should include a section voicing concerns about specific areas of the section language. Based on the written materials that are submitted, the Committee may wish to hold a separate hearing to further consider the rule language. Alternatively, if it is clear at the hearing that parties generally favor the tone and content of Section 4, then staff recommends the Committee endorse the language soon after reviewing written comments from stakeholders.

Section 5: The language contained in Section 5 of the proposed Rule should be fully endorsed by the Committee. The issue of cost allocation is a rate design issue that is more appropriate to address in the Phase 2 testimony of the CPUC rulemaking.

Section 6: Staff recommends that the Committee endorse the rule language applicable to Sections 6.1,.6.2, 6.5, 6.6, and 6.7. Since agreement on the language of Sections 6.3 and 6.4 was not possible, specific time at the April 25th hearing will be placed on the agenda to debate the issue in front of the Committee.

Staff also recommends that Section 6 specifically note that the UDC is to develop and forward to the Energy Commission an interconnection database. Appropriate language should be developed by the working groups over the next month and included in the final language recommended by the Committee to the Energy Commission.

Section 7: Staff believes that additional work is needed to further refine the dispute language. While the concerns noted by parties are quite valid and deserving of consideration, staff believes that the proposed language is appropriate for the Committee to endorse. Recognition should be given that additional work should be done in this subject area after interim Rule language is adopted by the CPUC.

Section 8: Staff recommends the Committee endorse the definition language contained in Section 8.

Regarding the applicability of the proposed Rule language to entities not subject to CPUC jurisdiction, staff recommends that the Committee work with CMUA to encourage municipalities and irrigation districts to adopt Rule 21-type rules that could further encourage standardized interconnection rules across the entire state.

In summary, staff believes that the proposed Rule language, combined with the potential willingness of municipalities and irrigation districts to adopt similar rules, will remove significant barriers to distributed generation technologies entering the California market.

VI. NEXT STEPS

The next step in this proceeding is the April 25th hearing to address the issues raised in this report. Written comments are due at the Energy Commission Docket Office filed by close of business on May 2nd.

After review of the written comments, additional discussions between the working groups, staff, and the Committee, the Committee will develop its final recommendation on interconnection rules. That recommendation is scheduled to be complete by the end of May. The Energy Commission will then consider the Committee's recommendation at a business meeting at the end of June.

The CPUC will then take the Energy Commission recommendation, provide an additional 21 days for parties to submit written materials commenting on the Energy Commission process and factual misrepresentations, and submit a proposed decision for ultimate CPUC adoption. The timing associated with the CPUC's proposed decision on interconnection rules is scheduled for November, in conjunction with a proposed decision on other R.99-10-025 Phase 1 issues. It is possible, however, that the interconnection issue could be addressed earlier than November in a proposed decision that is separate from the other Phase 1 issues.

ATTACHMENT A – Rule 21

(Compilation of Rule language and comments from specific working group participants)

DG Interconnection Revised Rule 21:
Compilation Document

1. APPLICABILITY AND INTRODUCTION

1.1 **Applicability** This Rule describes the interconnection, operating and metering requirements for Generating Facilities that are intended to be connected to the Distribution System over which the California Public Utilities Commission (CPUC) has jurisdiction. Subject to the requirements of this Rule, Electric Corporation will allow the interconnection of Generating Facilities with its Distribution System.

1.2 **Definitions** Capitalized terms used in this Rule, and not otherwise defined, shall have the meaning ascribed to such terms in Section 8.

1.3 **Enabling Documents** It is contemplated that the Applicant will be required to execute various enabling documents, such as the Application and Interconnection Agreement. Such documents shall be in the form on file with the CPUC, as may be amended from time to time.

{Solar Development Cooperative, 022800: For these documents to be fair and enforceable, it is important to reference where information originated from. While the references may not be included in the final codes published by the Commission, referenced Workshop Reports will save substantial time and confusion for the Commission as they establish the Rules for the UDC's role in DG. Although time is an issue, it will be an even larger problem if the Commission must attempt to verify every comment. Where portions of the document are simply semantic changes from an original document like Rule 21, stating this at the beginning of the document is the best approach with substantial changes or comments referenced throughout.}

2. GENERAL RULES, RIGHTS AND OBLIGATIONS

{Honeywell, 040100: Throughout this proceeding, the distributed generation community has attempted to support rules that could give their business community the certainty that it needs to make decisions within a competitive market. Though not every participant will support every aspect of the proposed rule, the certainty of a final regulatory decision will permit the market participants to take risks that they understand and can manage. For this reason, the second principle -- relating to utility discretion -- has remained important to Honeywell and other potential market participants.

Honeywell offers on the significant policy issues that affect the proposed Rule 21. It may be appropriate to address these matters in the body of the CEC staff report. There is a concern that decisions made regarding Rule 21 could affect future policy decisions in this proceeding. Because the status quo (today's utility practice) was the basis for several decisions, it may imply that the status quo is best in the future. Honeywell believes that future policy decisions should be based on what is best for customers and for the competitive process, and not on the status quo which was workable under a different regulatory regime. }

2.1 **Authorization Required to Interconnect** An Electricity Producer must comply with this Rule, form an Interconnection Agreement with Electrical Corporation, and receive Electrical Corporation's express written permission to interconnect before connecting or operating a

Generating Facility in parallel with the Electrical Corporation's Distribution System. Electrical Corporation shall apply this Rule in a non-discriminatory manner and shall not unreasonably withhold its permission to interconnect an Electric Producer's Generating Facility.

{Solar Development Cooperative 022800: Interconnection requirements are based on objective criteria ~~and~~, but are ~~not~~ subject to the special discretion of the UDC where interconnection of a Generating Facility may effect the safety, health and/or welfare of the public. Each UDC shall apply this rule in a non-discriminatory manner.}

2.2 **Separate Arrangements Required for Other Services** An Electricity Producer requiring other electric services from the Electrical Corporation including, but not limited to, Distribution Service provided by the Electrical Corporation during periods of curtailment or interruption of a Generating Facility, must enter into separate arrangements with Electrical Corporation for such services in accordance with CPUC-Approved tariffs.

2.3 **Transmission Service Not Provided with Interconnection** Interconnection with the Electrical Corporation's Distribution System under this Rule, does not provide an Electricity Producer any rights to utilize Electrical Corporation's Distribution System for the transmission or distribution of electric power, nor does it limit those rights.

{C. Vance & T. O'Sullivan /Hetch Hetchy Water & Power, date undetermined: Alternative 2.3: Interconnection with the UDC's electric system under this Rule does not provide a Producer any rights to utilize UDC's electric system for the transmission or distribution of electric power, nor does it limit those rights.}

{NewEnergy, 030800: The Producer shall comply with all applicable laws, rules and regulations, including applicable UDC rules, tariffs and requirements for operation of its Generating and Interconnection facility. }

2.4 **Compliance with Laws, Rules, and Tariffs** An Electricity Producer shall ascertain and comply with the applicable CPUC-approved rules, tariffs, and regulations of the Electrical Corporation and any local, state or federal law, statute or regulation which applies to the design, siting, construction, installation, operation, or any other aspect of the Electricity Producer's Generating Facility and Interconnection Facilities.

{CMUA, 031000: The Producer shall ascertain and comply with all applicable laws, rules, requirements and regulations (including all of the Electrical Corporation's rules, tariffs and requirements) applicable to the design, siting, construction, installation or operation of the Distributed Generator and Interconnection Facilities.}

{Cogeneration Association of California and Energy Producers and Users Coalition, 022800: Any requirement of the ISO would first have to be implemented by FERC or the CPUC or consented to in a bilateral agreement in order to be operative. }

{Solar Development Cooperative 022800: (a) The Producer shall ascertain, comply with and be responsible for ongoing compliance with the requirements of the ISO and all government authorities having jurisdiction over . . . interconnection equipment.
(b) The UDC shall be responsible to provide written notice to a Producer where they have knowledge that the Producer's Facility is not in compliance with the requirements of the ISO and all government authorities having jurisdiction over the design, siting, construction, installation, operation, or any other aspect of its Generating Facility and interconnection equipment.
(c) Where a UDC is found to have knowingly omitted pertinent information during the Impact Study, related installation and interconnection process, or fail to provide written notice to the Producer after they have become aware a Facility they have interconnected is not in compliance with local, state or federal laws, the UDC would share liability for related damage the Facility causes or incurs as a result of non-compliance. }
{Editorial comment, undated: [ISO has expressed the belief that it (ISO) should be mentioned in Paragraph 2.4. Most parties do not believe that mention of ISO is necessary.]}

2.5 **Design Reviews and Inspections** Electrical Corporation shall have the right to review the design of an Electricity Producer's Generating Facility and Interconnection Facilities and to inspect an Electricity Producer's Generating and/or Interconnection facilities prior to the commencement of Parallel Operation with Electrical Corporation's Distribution System. Electrical Corporation may require an Electricity Producer to make modifications as necessary to comply with the requirements of this Rule. Electrical Corporation's review and authorization for Parallel Operation shall not be construed as confirming or endorsing the Electricity Producer's design or as warranting the Generating and/or Interconnection Facility's safety, durability or reliability. Electrical Corporation shall not, by reason of such review or lack of review, be responsible for the strength, adequacy, or capacity of such equipment.

{Enron, 033100: 1. Section 2.5 allows the Electrical Company (EC) to inspect the Generating Facilities. To the extent that the interconnection facilities are not incorporated in the Generation Facility, the EC should not have the right to inspect the generating facilities, only the interconnection facilities. Therefore, Generating Facilities should be deleted from this section.}

{Capstone, 030100: Section 2.5 should be deleted. The key point of 2.5 relevant to the General section is that a generator must not operate in parallel until the UDC has verified that it meets the interconnection standards. The secondary point is that the UDC will have the right to inspect in order to verify compliance. Inspection is a matter of process and need not be included in the General Section.}

{Solar Development Cooperative, 022800: UDC site review of a Facility design and interconnection equipment is mandatory for Generating Facilities over 10 kW.}

{C. Vance & T. O'Sullivan /Hetch Hetchy Water & Power Alternative 2.5, date undetermined: The UDC shall have the right to review and approve the design of a Producer's interconnection facilities for conformance with the requirements of this rule. The UDC shall be given adequate notice and may witness the testing of any equipment and protective systems associated with the interconnection-prior to the commencement of parallel operation with the UDC's electric system. [Comment: Point here is that in Texas UDC doesn't order the tests.] The UDC may require a Producer to make modifications as necessary to comply with the requirements of this Rule. UDC's review and approval of the Producer's design shall not be construed as confirming or endorsing the Producer's design or as warranting the generating facility's safety, durability or reliability. UDC shall not, by reason of such review or lack of review, be responsible for the strength, details of design adequacy, or capacity of equipment built pursuant to such design, nor shall UDC's approval be deemed an endorsement of such equipment.}

{Dave Townley /New Energy Tech Alternative, date undetermined: The UDC shall have the right to review the design of a Producer's generating and interconnection facilities and to inspect the Producer's generating and interconnection facilities prior to the commencement of parallel operation with the UDC's electric system in order to confirm that the design and installation comply with the requirements of this Rule. The UDC may require a Producer to make modifications as necessary to comply with the requirements of this rule. The UDC's review of the Producer's design shall not be construed as confirming or endorsing the Producer's design or as warranting the generating facility's safety, durability or reliability. The UDC shall not, by reason of such review or lack of review, be responsible for the strength, details of design adequacy, or capacity of equipment built pursuant to such design, nor shall the UDC's review be deemed an endorsement of such equipment.}

2.6 **Right to Access** An Electric Producer’s Generating Facilities and Interconnection Facilities shall be reasonably accessible to Electrical Corporation personnel as necessary for Electrical Corporation to perform its duties and exercise its rights under its tariffs and rules filed with and approved by the CPUC, and any agreement between Electrical Corporation and the Electricity Producer.

2.7 **Confidentiality of Information** Any information pertaining to Generating and/or Interconnection Facilities provided to Electrical Corporation by an Electricity Producer shall be treated by Electrical Corporation in a confidential manner. Electrical Corporation shall not use or disclose information provided by an Applicant to propose competing Generating Facility installations to the Applicant.

{Honeywell, 040100: Section 2.7 restricts the use of information by the UDC to propose competing generating facilities installations to the customer/applicant. Honeywell believes that this restriction does not go far enough. It is possible for a utility to use the knowledge of an interconnection application to propose discounted rate alternatives to the customer. Honeywell acknowledges that any customer could approach the utility to seek discounted rates, and that the utility is authorized to offer discounted rates. The timing of the request for interconnection provides competitive information that could be used to interfere with the business relationship between the customer and the DG service provider.}

{Enron, 033100: Section 2.7 should be rewritten such that the EC cannot disclose any information to anyone outside of the EC's company (not just the "Applicant" as written in the section}.

{Coast Intelligen, 032800: Affiliate rules may not prohibit exchange of this information; if not, affiliates would have unfair competitive advantage.}

2.8 **Prudent Operation and Maintenance Required** An Electricity Producer shall operate and maintain its Generating Facility and Interconnection Facilities in accordance with Prudent Electrical Practices and shall maintain compliance with CPUC adopted standards for the Electricity Producer's particular Generation and Interconnection Facilities. Said standards shall be those in effect at the time an Electricity Producer executes an Interconnection Agreement with Electrical Corporation.

2.9 **Protection of Producer’s Facilities** An Electricity Producer shall be solely responsible for providing adequate protection for the Electricity Producer's Generating Facility and Interconnection Facilities connected to Electrical Corporation's Distribution System.

{Dave Townley /New Energy Tech, date undetermined: Alternative 2.9: A generating facility may not be operated in parallel with the UDC's electric system until and unless the UDC has determined that such generating facility and related interconnection facilities comply with the design and operating requirements set forth in this Rule and provided the Producer with a written authorization to operate in parallel with the UDC electric system.}

{Solar Development Cooperative, 022800: The UDC must provide written notification to the Producer where they become aware a Generating Facility or its interconnection equipment are not in compliance with UDC Rules and/or local, state or federal laws. The UDC must make reasonable efforts to inform a Producer of needed safety equipment during the Impact Study for interconnection and/or its subsequent components.}

2.10 **Curtailment and Disconnection** Electrical Corporation may limit the operation and/or disconnect or require the disconnection of an Electricity Producer’s Generating Facility from Electrical Corporation’s Distribution System at any time, with or without notice, in the event of an Emergency, or to correct Unsafe Operating Conditions. Electrical Corporation may also limit the operation and/or disconnect or require the disconnection of an Electricity Producer’s Generating Facility from Electrical Corporation’s Distribution System upon the provision of reasonable notice: 1) to allow for routine maintenance, repairs or modifications to Electrical Corporation’s Distribution System; 2) upon Electrical Corporation’s determination that an Electricity Producer’s Generating Facility is not in compliance with this Rule; or, 3) upon termination of the Interconnection Agreement.

{Coast Intelligen, 033000: Allowing the utilities to unilaterally determine/interpret whether a Producer's facility is or is not in compliance with the Rule is wrong. That is too much decision making authority in the hands of utilities, with no redress for the Producer.}

{CMUA, 031000: The UDC shall treat as confidential all information relating to interconnection and the installation of Distributed Generation. Without limiting the generality of the foregoing, an Electrical Corporation shall not use this information to prepare competing proposals to the customer that offer competing Distributed Generation projects. {In the previous version, emphasis was placed on “knowledge” of proposed projects. The Electrical Corporation should not be hindered from making a proposal merely because of its knowledge of the Producer’s proposed project. Rather, the key is to protect the confidential information, and not allow the Electrical Corporation to use the confidential information in developing its own proposal}

{Hetch Hetchy Water and Power, 032900: The language we proposed adding to the end of this section is as follows: "Incremental demand charges arising from disconnecting the distributed generator as directed by the Electric Corporation during such periods shall not be assessed by Electric Corporation to the Electricity Producer."

{Solar Development Cooperative, 022800: (a) Utility Services provided by the UDC during periods of curtailment or interruption of a Generating Facility shall be provided and <u>reasonably</u> billed pursuant to the applicable UDC tariffs filed with the CPUC. <u>(b) Interconnection and tariff agreements like net metering shall remain enforce for the life of the longest warranty of the generating equipment installed in the Facility to protect the Producer’s investment. Where a Generating Facility is installed and in compliance with local,</u>

state and federal laws that existed at the time of the installation, a Facility may not be disconnected due to subsequent legislation or decisions unless the Facility effects the health, safety and/or welfare of the public. Producer relies on the agreement with the UDC to secure financing for the system representing a long-term investment. Where disconnection action is taken by the UDC before the life of the longest warranty on the Generation Facility has expired, such case would represent a breach of contract. Where this disconnection is not due to any fault of the Producer, the Producer shall be reasonably reimbursed for their losses and related stranded investments by the government agency that demands the disconnection.

Add the following the end of section 2.104) a Producer fails to timely remedy or attempt to remedy a condition or need made known to the Producer in writing by the UDC or other local, state or federal agency that effects the safety, health and/or welfare of the public. }

3. APPLICATION AND INTERCONNECTION PROCESS

{Honeywell, 040100: The comments of Honeywell, NewEnergy, and Capstone support the reevaluation of policies relating to fees and charges for interconnection. Many parties acknowledge that fees and charges relating to interconnection are matters that must be addressed in the rate design phase of this proceeding. There is a concern that if these matters were addressed as part of Rule 21, the status quo would prevail, and the broader policy issues would not be subject to change. Existing practice requires that power producers pay the incremental costs of interconnection. These costs include an application fee, the costs associated with system studies performed by the UDC, and the cost of any upgrades to distribution facilities necessary prior to the interconnection. This cost allocation approach worked in the past, but may not work in the future. Honeywell believes that this practice discriminates against DG customers, and is therefore unfair. Averaging of certain utility costs among all customers may be more appropriate to ensure that all competitive options are given an equal opportunity. In the future, continuation of the existing practice could result in the subsidization of traditional purchasing customers by DG customers.

The present language of proposed Rule 21 is based on the status quo requiring all power producers to pay all incremental costs. If this policy changes in the future, the following subsections of proposed Rule 21 may require modification: Sec. 3.2.2; Sec. 3.2.3.4; Sec. 3.2.3.5; Sec. 3.2.4; Sec. 3.2.5; Sec. 3.2.6; Sec. 3.2.9; Sec. 5.2.1; Sec. 5.2.2; Sec. 5.2.3; Sec. 5.3.1; Sec. 5.3.3; and Sec. 5.3.5.}

3.1 Application Process

3.1.1 **Applicant Initiates Contact with the Electrical Corporation** Upon request , the Electrical Corporation will provide information and documents (such as an application form, contract and technical requirements, specifications, listing of Certified Equipment, application fee information, applicable rate schedules and metering requirements) in response to the potential Applicant's inquiry. Unless otherwise agreed upon, all such information and a copy of the Electrical Corporation's standardized interconnection requirements shall normally be sent to the Applicant within three (3) business days following the initial request from the Applicant. The Electrical Corporation will establish an individual representative as the single point of contact for the Applicant, but may allocate responsibilities among its staff to best coordinate the Interconnection of a Applicant's Generating Facility.

{C. Vance & T. O'Sullivan /Hetch Hetchy Water & Power, date undetermined: Alternative 3.1.1

This initial communication process may range from a general inquiry by an interested party to a Producer providing a fully completed application. Contact may be by phone, mail, e-mail, facsimile, or in person.

A UDC representative will discuss the scope of the project with a potential Producer (either by phone or in person) to determine what specific information and documents (such as an application, contract, technical requirements, specifications, listing of qualified type-tested equipment/systems, application fee information, applicable rate schedules and metering requirements) will be provided in response to the Producer's inquiry. The preliminary technical feasibility of the project at the proposed location may also be discussed at this time. Unless otherwise agreed upon, all such information and a copy of the UDC's standardized interconnection requirements shall be sent to the Producer within three (3) business days following the initial communication from the potential Producer. The UDC will ~~normally~~ establish an individual representative as the single point of contact for the Producer, but may allocate responsibilities among its staff to best coordinate the interconnection of a Producer's generating facility. [Comment: We understand that multiple staff members would be involved. The point here is to have one individual that is accountable for coordinating all communications.] Also Insert New Language From Texas 25.211(j)

In the course of processing applications for interconnection and parallel operation and in the conduct of pre-interconnection studies, customers shall provide the utility detailed information concerning proposed distributed generation facilities. A utility and its affiliates shall not use such knowledge of proposed distributed generation projects submitted to it for interconnection or study to prepare competing proposals to the customer that offer either discounted rates in return for not installing the distributed generation, or offer competing distributed generation projects.}

3.1.2 **Applicant Completes an Application Document** All Applicants shall be required to complete and file an Application document and supply any additional information requested by the Electrical Corporation. The filing must include the completed standardized Application, which may be either in paper or electronic form, and a fee for processing the application and performing the Initial Review to be completed by the Electrical Corporation pursuant to Section 3.2.3. The application fee shall be non-refundable and shall vary with the nature of the proposed generating facility as follows:

Type of Generating Facility	Application Fee	
Net energy Metering (per P.U. Code Sec. 2827)	None	
< 11 kVA	$ (Fixed; amount TBD)______	
All others	$(Fixed; amount TBD)_______	

Within ten (10) business days of receiving an application, the Electrical Corporation shall normally acknowledge its receipt and whether the application has been completed adequately. If defects are noted, the Electrical Corporation and Applicant shall cooperate in a timely manner to establish a satisfactory application.

3.1.3 **Electrical Corporation Performs an Initial Review and Develops Preliminary Cost Estimates and Interconnection Requirements**

3.1.3.1 Upon receipt of a satisfactorily completed Application and any additional information necessary to evaluate the Interconnection of a generating facility, the Electrical Corporation shall perform an Initial Review using the process defined in Appendix A. The Initial Review determines if the Application qualifies for Simplified Interconnection, if the Application can qualify for Interconnection subject to additional requirements, or if it will be necessary for Electrical Corporation to perform an Interconnection Study to determine Interconnection Requirements.

3.1.3.2 The Electrical Corporation shall normally complete its Initial Review within 10 business days if the Application qualifies for Simplified Interconnection. If the Initial Review determines that the proposed facility can be interconnected by means of a Simplified Interconnection, the Electrical Corporation will provide the Applicant with a written description of the requirements for interconnection and a draft Interconnection Agreement pursuant to Section 3.2.5.

3.1.3.3 If the Application does not qualify for Simplified Interconnection as submitted, the Initial Review will include a supplemental review as described in Appendix A. The supplemental review provides either (a) Interconnection Requirements that may include requirements beyond those for Simple Interconnection, and a draft Interconnection Agreement, or (b) a cost estimate and schedule for an Interconnection Study. The supplemental review will normally be completed within 20 business days of receipt of a completed Application.

3.1.4. **When Required, Applicant and Electrical Corporation Commit to Additional Interconnection Study Steps** When an Initial Review reveals that the proposed facility cannot be interconnected to the Electrical Corporation's system by means of a simplified interconnection pursuant to Section 4 and Appendix B, and that significant Electrical Corporation Interconnection Facilities or Distribution System Improvements must be installed or made to the Electrical Corporation's electric system to accommodate the interconnection of an Applicant's generating facility, the Electrical Corporation and Applicant shall enter into an agreement that provides for the Electrical Corporation to perform such additional studies, facility design, and engineering and to provide detailed cost estimates for fixed price or actual cost billing, to the Applicant at the Applicant's expense. The Interconnection Study Agreement shall set forth the Electrical Corporation's schedule for completing such work and the estimated or fixed price costs of such studies and engineering. Upon completion of an interconnection study, the electrical Corporation shall provide the Applicant with the specific requirements, costs and schedule for interconnecting the generating facility to accommodate execution of agreements pursuant to section 3.1.5.

{Capstone, 030300: Suggested revision "...the UDC to perform such additional studies, design, engineering and provide a firm quotation of those costs that the UDC is entitled to charge the Producer. " }

3.1.5 **Applicant and Electrical Corporation Enter Into a Generation Interconnection Agreement and, Where Required, a Financing and Ownership Agreement for Interconnection Facilities or Electric System Modifications** The Electrical Corporation shall provide the Applicant with an executable version of the generation interconnection, net energy metering, or power purchase agreement appropriate for the Applicant's generating facility and desired mode of operation. Where the Initial Review or Interconnection Study performed by the Electrical Corporation has determined that modifications or additions are required to be made to its electric system, or that additional metering, monitoring, or protection devices will be necessary to accommodate a Applicant's Generating Facility, the Electrical Corporation shall also provide the Applicant with an Interconnection Facilities Financing and Ownership Agreement (IFFOA). The IFFOA shall set forth the respective parties' responsibilities, completion schedules, and estimated or fixed price costs for the required work.

{Enron, 033100: The only "system modifications" that should be performed by the EC are those necessary to interconnect the facility. System modifications necessary to facilitate the "wheeling" of energy into and over the distribution system should be done separately and under a different (wheeling?) agreement. Interconnection agreements should only be for interconnecting with the grid, use of the grid for distribution purposes.}

3.1.6 **Electricity Producer Installs or Constructs the Generating Facility; Where Applicable, Electrical Corporation or Electricity Producer Installs Required Interconnection Facilities or Modifies Electrical Corporation's Electric System** After executing the appropriate Generation Interconnection or Power Purchase Agreement, and where required, the IFFOA, the Electricity Producer may install or construct its Generating Facility in accordance with the provisions of this rule and the terms of the specific agreements formed between the Electricity Producer and the Electrical Corporation. Where appropriate, the Electrical Corporation will commence construction/installation of the system modifications and/or metering and monitoring requirements identified in the IFFOA. The parties will use good faith efforts to meet the schedules and fixed costs or estimated costs in the IFFOA.

{Enron, 033100: This section implies that after executing the Interconnection or Power Purchase Agreement, the EP may install or construct its Generating Facility. The EP should be permitted to install the Generating Facility without these agreements, but should not be permitted to install the Interconnection Facilities until the agreement(s) is executed. Therefore, "Generating Facility " in this section should be changed to "Interconnection Facility.}

3.1.7 **Electricity Producer Arranges for and Completes Testing of Generating Facility and, Where Applicable, Electricity Producer Installed Interconnection Facilities** New generating facilities and associated interconnection facilities must be tested to ensure compliance with the safety and reliability provisions of the CPUC-approved rules and regulations prior to being operated in parallel with the Electrical Corporation's electric system. Certified Equipment will be subject to the tests specified in Section 4. For non-Certified Equipment, the Electricity Producer will develop a written testing plan to be submitted to the Electrical Corporation for its review and acceptance. Alternatively, the Electricity Producer and Electrical Corporation may agree to have the Electrical Corporation conduct the required testing at the Electricity Producer's expense. Where applicable, the test plan shall include the installation test procedure(s) published by the manufacturer(s) of the generation or interconnection equipment. Facility testing shall be conducted at a mutually agreeable time, and depending on who conducts the tests, the Electrical Corporation or Electricity Producer shall be given the opportunity to witness the tests.

{Solar Development Cooperative 022800: The Producer is encouraged to consult with the UDC staff who are in a position to be familiar with most Generating Facility technology and Interconnection Equipment. The UDC generally knows, and is responsible to assess the potential needs for testing because they have historically been in the business of facilitating a variety of electricity generation due diligence related to interconnection to the UDC Grid System. UDC's due diligence or lack thereof does not limit the manufacturer's or Producer's liability for product or Generating Facility performance, but could result in shared liability.}

{Dave Redding / Riverside, date undefined: Suggest the second sentence be modified as noted: "Preapproved, type-tested units will be subject only to the installation or commissioning inspections tests specified in Section 4 If a unit is 'preapproved, type-tested,' it should mean that a unit has been proven to meet certain performance criteria and the UDC must accept those results. It should not mean that no testing is required for a specific unit being installed, or that the manufacturer is automatically in a position to dictate what on-site tests are appropriate. The Technical Working Group needs to establish the test requirements for inclusion in the Rule. As originally written, the sentence does not make it clear whether the manufacturer or the UDC has the final say on what inspections/test are required.}

3.1.8 **Electrical Corporation Authorizes Interconnection** The Electricity Producer's Generating Facility shall be allowed to commence parallel operation with the Electrical Corporation's electric system upon satisfactory compliance with the terms of the interconnection, Power Purchase Agreement or Net Energy Metering Agreement. Compliance may include, but not be limited to, provision of any required documentation and satisfactorily completing any required inspections or tests as described herein or in the agreements formed between the Electricity Producer and the Electrical Corporation. A Electricity Producer shall not interconnect a generating facility unless it has received the Electrical Corporation express written permission to do so.

3.1.9 **Electrical Corporation Reconciles Costs and Payments** If the Electricity Producer selected a fixed price cost for the Interconnection Facilities or Electric System Modifications, no reconciliation will be necessary. If the Electricity Producer selected actual cost billing, a true-up will be required. Within a reasonable time after the interconnection of a Electricity Producer's generating facility, the Electrical Corporation will reconcile its actual costs related to the Electricity Producer's facility against the application fee and any other advance payments made by the Electricity Producer. The Electricity Producer will receive either a bill for any balance due or a reimbursement for overpayment as determined by the Electrical Corporation's reconciliation. The Electricity Producer shall be entitled to reasonably detailed and understandable report detailing the Electrical Corporation's reconciliation process.

{Capstone, 030300: Delete section 3.2.9}

{Honeywell, 022500: Key objectives of regulated ratemaking are the determination of cost causation and the fair treatment of affected parties. The following text makes assumptions about cost allocation and payment. Cost allocation issues will be discussed in the rate design phase of this proceeding, and it is inappropriate to adopt conclusory language at this time.}

{Solar Development Cooperative, 022800:
<u>The Producer is encouraged to consult with the UDC staff who are in a position to be familiar with most Generating Facility technology and Interconnection Equipment. The UDC generally knows, and is responsible to assess the potential needs for testing because they have historically been in the business of facilitating a variety of electricity generation due diligence related to interconnection to the UDC Grid System. UDC's due diligence or lack thereof does not limit the manufacturer's or Producer's liability for product or Generating Facility performance, but could result in shared liability</u>.

{Independent System Operator (ISO), date undetermined: As we have discussed in the context of planning, it would be helpful to the ISO to have information about what distributed generation is located where within the distribution system. Accordingly, the ISO would like to be notified when an application is submitted and when an interconnection is completed. I believe that if we can agree that this should occur, it should be reflected in the rule so that applicants are aware that this is going to happen. A provision could be added to Proposed rule 21, section 3, which states:

> **Notification to the ISO** The UDC will notify the ISO when it receives an application to interconnect and when it allows an interconnected generating facility to commence parallel operations.}

4. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS

4.1 **Purpose** The purpose of this section is to describe the requirements and procedures for safe and effective Interconnection and operation of Distributed Generation. Subsection 4.2

addresses general interconnection and protection requirements, subsection 4.3 addresses prevention of interference, and subsection 4.4 addresses control, safety and protection equipment requirements.

4.2 General Interconnection and protection requirements

4.2.1 The Distributed Generator and Interconnection installation must meet all applicable national, state, and local construction and safety codes.

4.2.2 Interconnection protection schemes must comply with this rule.

4.2.3 The Protective Functions shall be equipped with automatic means to prevent the Generating Facility from re-energizing a de-energized Distribution System circuit.

4.2.4 The Generating Facility and associated Protective Functions shall not contribute to the formation of an Unintended Island.

4.2.5 The Electricity Producer's protection and control diagrams for the Interconnection need to be approved by the Electrical Corporation prior to completion of the Generating Facility Interconnection, unless the Electricity Producer uses a protection and control scheme previously approved by the Electrical Corporation or uses only Certified Equipment.

4.2.6 The Protective Functions shall be equipped with automatic means to prevent Parallel Operation of the Generating Facility with the Distribution System unless the Distribution System service voltage and frequency is of specified settings and is Stable for 60 seconds

4.2.7 Certified Equipment contains certified functions that are accepted by all California Electrical Corporations. This equipment may be installed on a Distribution System in accordance with an Interconnection control and protection scheme approved by the Electrical Corporation.

4.2.8 These requirements are designed to protect the interconnected Distribution System and not the Generating Facility. The Electricity Producer's protective equipment shall not impact the operation of the Distribution System protective devices in a manner that would affect the Electrical Corporation's capability of providing reliable service to Customers.

4.2.9 Circuit breakers or other interrupting devices at the Point of Common Coupling (PCC) must be Certified or "Listed" (as defined in Article 110, National Electrical Code) as suitable for the application. This includes being capable of interrupting maximum available fault current. The Generating Facility shall be designed so that the failure of any one device shall not potentially compromise the safety and reliability of the Distribution System.

4.2.10 The Electricity Producer will furnish and install a manual disconnect device that has a visual break to isolate the Generating Facility from the Distribution System that is appropriate to the voltage level, and is accessible to the Electrical Corporation personnel, and capable of being locked in the open position. (exception: Distributed Generators connected to the Distribution System through a non-islanding inverter smaller than 1kVA)

4.3 **Prevention of interference** The Electricity Producer shall not operate equipment that superimposes upon the Distribution System a voltage or current that causes interference with Electrical Corporation operations, service to Electrical Corporation Customers or interference to communication facilities. If the Electricity Producer causes service interference to others, the Electricity Producer must diligently pursue and take corrective action at its own expense after being given notice and reasonable time to do so by the Electrical Corporation. If the Electricity Producer does not take timely corrective action, or continues to operate the equipment causing interference without restriction or limit, the Electrical Corporation may, without liability, disconnect the Electricity Producer's equipment from the Distribution System, in accordance with subsection 2.10 of this rule, until a permanent solution provided by the Electricity Producer is operational.

To eliminate undesirable interference caused by operation of the Distributed Generator, the Distributed Generator shall meet the following criteria:

Normal voltage operating range The voltage operating range for Distributed Generators is selected as a protection function that responds to abnormal Distribution System conditions, not as a voltage regulation function.

Small systems (11 kVA or less) Distributed Generator systems of 11 kVA capacity or less should be capable of operating within the limits normally experienced on the Distribution System. The operating window shall be selected in a manner that minimizes nuisance tripping. The operating window for these small systems is 106 to 132 volts on a 120-volt base. That is, 88% to 110% of nominal voltage. This results in trip points at 105 volts and at 133 volts. The requirement of this subsection is that the Distributed Generator cease to energize the Electrical Corporation lines whenever the voltage at the PCC deviates from the allowable voltage operating range of 88% to 110% of nominal voltage.

Systems larger than 11 kVA Electrical Corporations may have specific operating voltage ranges for larger Distributed Generator units, and may require adjustable operating voltage settings for these larger systems. In the absence of such requirements, the above principles of operating between 88% and 110% of the appropriate interconnection voltage should be followed.

Voltage Disturbances System voltage assumes a nominal 120 V base. For the convenience of those wishing to translate these guidelines to voltage bases other than those 120V, the limits will also be provided as approximate percentages. The inverter should sense abnormal voltage and respond. The following conditions should be met, with voltages in RMS and measured at the PCC:

Table 4.1 – Response to Abnormal Voltages

Voltage (at PCC)		**Maximum Trip Time***
V< 60	(V<50%)	10 cycles
60£V<106	(50%£V<88%)	120 cycles
106£V£132	(88%£V£110%)	Normal Operation
132<V<165	(110%<V<137%)	120 cycles (30 cycles for DG >11 kVA)
165£V	(137%£V)	6 cycles

*"Trip time" refers to the time between the abnormal condition being applied and the Distributed Generator unit ceasing to energize the Distribution System. Certain circuits will actually remain connected to the Distribution System to allow sensing of electrical conditions for use by the "reconnect" feature. The purpose of the allowed time delay is to ride through short-term disturbances to avoid excessive nuisance tripping. For systems of 11 kVA peak capacity or less, the above set points are to be non-user adjustable. For Distributed Generator units larger than 11 kVA, different voltage set points and trip times from those in Table 4.1 may be negotiated with the interconnecting Electrical Corporation.

Flicker Any voltage flicker at the PCC caused by the Distributed Generator should not exceed the limits defined by the "Maximum Borderline of Irritation Curve" identified in IEEE 519. This requirement is necessary to minimize the adverse voltage effects to other customers on the Distribution System. Induction generators may be connected and brought up to synchronous speed (as an induction motor) provided these flicker limits are not exceeded.

Low frequency settings of 59.3 Hz and 58.0 Hz may be made available as per the requirements in Appendix B of this rule*.*

Harmonics Harmonic distortion shall be in compliance with IEEE 519. Exception: The harmonic distortion of a Distributed Generator at a Customer's site shall be evaluated using the same criteria as the loads at that site.

{Robert Wichert, USFuel Cell Council, 032400: Not to take issue with the requirement to meet IEEE 519, but our Interconnect-3 Industry Working Group has decided to endorse lab testing to meet IEEE 519, NOT field testing. This was in response to a remark by someone after that last IEEE P1547 meeting pointing out that generators should not be penalized any more than motors. I agree. It would be better to REQUIRE testing to IEEE 519 in the lab for pre-certified systems, with a specific set of conditions expected to be "worst case" and ONLY require field testing to IEEE 519 if the system is not pre-certified. One day of field testing is bound to add significant costs and isn't really necessary for pre-certified systems.}

{Chuck Whitaker, Endecon, 032400: There is currently no requirement in the testing section for 519 as a field test. The only cases where I would see the need for field certification to 519 would be by request of the mfg/installer, or where specific filtering or harmonics canceling algorithms were implemented to improve the situation at a particular site.}

{Robert Wichert, USFuel Cell Council, 032400: [Suggests that needs to be spelled out. -ed]}

{Simon Wall, Capstone, 032400: Those of you involved in the IEEE P1547 Interconnection Standard will be aware that I do indeed have definite opinions regarding the application of IEEE519-1992 to Distributed Generation. IEEE519-1992 applies different limits on the current harmonic levels at the PCC for loads and generators, which results in a major and unfair barrier to the adoption of DG. By way of justification for this statement please see the attached document that I distributed to the IEEE working group and the attached email that I sent to the group after some discussion of the document. I have also contacted the IEEE519 committee and requested interpretation of the areas of ambiguity mentioned in the email. IEEE519 is in currently being redrafted and both co-chairs indicated that they would give serious consideration to the issues raised concerning DG. IEEE519-1992 may have been an national consensus standard 8 years ago, but most DG manufacturers where not around then and did not have the opportunity to participate. I assume that the IEEE519 committee is re-drafting the standard because they too feel that it no longer reflects a consensus of interested parties.

For a voltage source DG such as synchronous and induction generators the use of the harmonic voltage limits in the original wording may have the best technical justification. For inverter based DG I agree with Doug that limiting current harmonics is more appropriate than limiting voltage harmonics. However, we should use the current harmonic limits for loads given in IEEE519-1992 rather than those for generators to avoid the problems outlined in the attached document. To accommodate all these considerations I would suggest modifying the section along the following lines.

4.3.5 Harmonics. The Distributed Generation installation must meet at least one of the requirements 1 to 3 listed below.

1) Type testing requirement 1 (applicable to all Distributed Generation types): The Distributed Generation equipment shall be connected to a voltage generation source where the Total Harmonic Distortion (THD) is no more than 5% of the fundamental voltage and where no individual harmonic voltage exceeds 3% of the fundamental voltage. The short circuit current capacity of the voltage generation source shall be 20 times the rated current of the Distributed Generation equipment. The harmonic current measured at the output of the Distributed Generation equipment must not exceed those limits given in IEEE519-1992 for power generation equipment, where the load current, IL, shall be deemed to be the rated current of the Distributed Generation equipment.

2) Type testing requirement 2 (applicable only to synchronous or induction generators): The harmonic voltage content of the open circuit voltage waveform shall not exceed those limits on harmonic voltage distortion given in IEEE519-1992.

3) Operating requirement: For Distributed Generation installations the harmonic current distortion measured at the Point of Common Coupling with the Distribution System shall not exceed those limits given in IEEE519-1992 for general loads, for the purpose of establishing these limits, the installation shall be deemed not to be "power generation equipment", "dispersed generation" or "cogeneration". }

Direct Current Injection The Distributed Generator should not inject dc current greater than 0.5% of rated output current into the Distribution System under either normal or abnormal operating conditions.

Power Factor The Distributed Generator shall be capable of operating at some point within a range of a power factor of 0.9 (either leading or lagging). Operation outside this range is acceptable provided the reactive power of the Distributed Generator is used to meet the reactive power needs of on-site loads. The Electricity Producer shall notify the Electrical Corporation if is using the Distributed Generator for power factor correction.

4.4 Control, protection and safety equipment requirements

4.4.1 Basic Requirements

4.4.1.1 **Protective function requirements** All Distributed Generators must have a visual open disconnect device, a fault-interrupting device, an over/under voltage trip function, and an over/under frequency trip function.

4.4.1.2 **Limits specific to single-phase generators** For single-phase generators connected to a shared single-phase secondary, the maximum capacity shall be 20 kVA. Distributed Generators applied on a center-tap neutral 240-Volt service must be installed such that no more than 6 kVA of imbalance in capacity exists between the two sides of the 240-Volt service. For dedicated distribution transformer services, the limit of a single-phase Distributed Generation shall be the transformer nameplate rating.

4.4.2 Technology Specific Requirements

4.4.2.1 **Three-phase synchronous generators** The Electricity Producer's Distributed Generator circuit breakers shall be three-phase devices with electronic or electromechanical control. The Electricity Producer is solely responsible for properly synchronizing its Distributed Generator with the Distribution System by means of either a manual or automatic synchronizing function. Automatic synchronizing is required for all synchronous generators which have a SCCR of greater than 0.05. Distributed Generators whose SCCR is greater than 0.05 shall be equipped with Protective Functions suitable for detecting loss of synchronism and rapidly disconnecting the DG from the Distribution System Unless otherwise agreed to between the Electricity Producer and the Electrical Corporation, synchronous generators shall automatically regulate power factor, not voltage, while operating in parallel with the Distribution System.

4.4.2.2 **Induction Generators** Induction Generators do not require separate synchronizing equipment. Starting or rapid load fluctuations on induction generators can adversely impact the Distribution System's voltage. Corrective step-switched capacitors or other techniques may be necessary and may cause undesirable ferroresonance. When these counter measures (e.g. additional capacitors) are installed on the Electricity Producer's side of the PCC, the Electrical Corporation must review these measures. Additional equipment may be required to resolve this problem as a result of an Interconnection Study.

4.4.2.3 **Inverter Systems** Utility-interactive inverters do not require separate synchronizing equipment. Non-utility-interactive stand-alone inverters shall not be used for parallel operation with the Distribution System.

4.4.3 **Initial Review process**

Appendix A of this rule defines the Initial Review process. The Initial Review process evaluates the specific characteristics of the Interconnection, including those specific to the location of the Generating Facility, and whether additional requirements are necessary.

4.4.4 **Supplemental DG Requirements**

This section deals with additional requirements to enable DG to interconnect that do not qualify for Simplified Interconnection.

4.4.4.1 **Unintended Islanding For DG that fail the Export Screen** Distributed Generators must mitigate their potential contribution to an Unintended Island. This can be accomplished by one of the following options:

(1) incorporating certified non-islanding control functions into the Distributed Generator's Protective Functions, or

(2) verifying that local loads sufficiently exceed the load carrying capability of the Distributed Generator, or

(3) transfer trip or equivalent function.

4.4.4.2 **Fault Detection** DG with an SCCR exceeding 0.1 or that do not meet any one of the options for detecting Unintended Islands in 4.4.4.1, shall be equipped with protective functions designed to detect Distribution System faults, both line-to-line and line-to-ground, and promptly remove the Distributed Generator from the Distribution System in the event of a fault. For Distributed Generators that cannot detect these faults within two seconds, transfer trip or equivalent function may be required. Reclose-blocking of the Electrical Corporation's affected recloser(s) may also be required for generators that exceed 15% of the peak load on the Line Section.

4.4.5 **Generating Facility types and conditions not identified** In the event that section 4 of this rule does not address the Interconnection requirements of a Generating Facility, the Electrical Corporation and Electricity Producer may interconnect a Generating Facility using mutually agreed upon technical requirements.

5. INTERCONNECTION FACILITY OWNERSHIP AND FINANCING

{NewEnergy, 033100: This section deals with the cost allocation of DG interconnection. The policy issues for cost allocation of DG interconnection is part of the rate design discussions and testimony in Phase II of the Commission's proceedings in 2000 on distributed generation. Because of this fact and the timing of the proceedings versus this effort to Revise rule 21, <u>the language within this section reflects how the cost allocation is currently instituted and does not prejudge how the commission should determine this matter.</u> This section as written provides a method of cost allocation during the interim period between when the Rule 21 is adopted and when the cost allocation questions are addressed by the Commission. Following the Commission's decision regarding cost allocations and rate design structure in this distributed generation proceeding, this section needs to be reviewed and revised for consistency, as necessary.

Some specific issues which are being challenged and may be determined by the Commission to be treated in a manner different than is described within this section include, but are not limited to:
Utility ownership of Interconnection Facilities on the customer side of the Point of Common Coupling; Customer or third party ownership of Interconnection Facilities on the utility side of the Point of Common Coupling; Cost allocation equity and consistency between what is done for/with customers without DG and those with DG; Cost allocation and/or ownership rights regarding system additions or modifications that create excess distribution capacity for the benefit others, including
Future load customers; Future DG customers, including provisions per line extension rules for rebates from future exporting DG customers; Fee treatment of the Interconnection Review and Interconnection Studies; Ownership and control of Interconnection Study results for a specific DG application;}

{Enron 033100: Section 5, - See comment 3 above. The only "System Reinforcements" or System Upgrades that should be included are those required to facilitate the interconnection only and not wheeling (export). If EP wants to export power to the grid, the EP should enter into a "distribution system agreement" (or something similar) which details the required system reinforcements and costs.

To the extent that the EP has to pay for upgrades and reinforcements, this section should also include the concept of the EP receiving exclusive rights to any upgrades/reinforcements paid for by the EP, including any additional capacity created (not just limited to the EP's needs). Another Section be added, Section 5.3.6 that says something to the effect: "Where any Special Facilities or any Electrical Corporation Interconnection Facilities are paid for by the EP, the EP retains exclusive rights to these facilities including any additional system capacity created by the Facilities."}

5.1 Scope and Ownership of Interconnection Facilities

5.1.1 **Scope** The interconnection of an Electricity Producer's Generating Facility with Electrical Corporation's Distribution System is made through the use of Interconnection Facilities. Such interconnection may also require Distribution System Improvements. The nature, extent and costs of Interconnection Facilities and Distribution System Improvements shall be consistent with this Rule and determined through the Initial Review and/or Interconnection Studies described in Section 3.

5.1.2 **Ownership** Subject to the limitations set forth in this Rule, Interconnection Facilities which may be installed on Electricity Producer's side of the Point of Common Coupling may be owned, operated and maintained by the Electricity Producer or Electrical Corporation. Interconnection Facilities installed on Electrical Corporation's side of the point of Common Coupling and Distribution System Improvements may be owned operated and maintained only by Electrical Corporation.

5.2 **Responsibility for Costs of Interconnecting a Generating Facility**

5.2.1 **Study and Review Costs** An Electricity Producer shall be responsible for the reasonably incurred costs of the Initial Review and any Interconnection Studies conducted pursuant to Section 3.2 of this Rule solely to explore the feasibility and determine the requirements of interconnecting a Generating Facility with Electric Corporation's Distribution System.

5.2.2 **Facility Costs** An Electricity Producer shall be responsible for all costs associated with Interconnection Facilities owned by the Electricity Producer. The Electricity Producer shall also be responsible for any costs reasonably incurred by Electrical Corporation in providing, operating, or maintaining Interconnection Facilities and Distribution System Improvements required solely for the interconnection of the Electricity Producer's Generating Facility with Electrical Corporation's Distribution System.

5.2.3 **Separation of Costs** Should Electrical Corporation combine the installation of Interconnection Facilities, or Distribution System Improvements with modifications or additions to the Electrical Corporation's Distribution System to serve other Customers or Electricity Producers, Electricity Corporation shall not include the costs of such separate or incremental facilities in the amounts billed to the Electricity Producer for the Interconnection Facilities or Distribution System Improvements required pursuant to this Rule.

5.3 **Installation and Financing of Interconnection Facilities Owned and Operated by Electrical Corporation**

5.3.1 **Agreement Required** Costs for Special Facilities shall be paid by Electricity Producer pursuant to the provisions contained in the Interconnection Agreement or, where the nature and extent of the Interconnection Facilities and Distribution System Improvements warrant additional detail, in a separate Interconnection Facility Financing and Operating Agreement between the Electricity Producer and Electrical Corporation, and Electrical Corporation's applicable tariffs and rules for Special Facilities.

5.3.2 **Attachments and Modifications to Distribution System** Except as provided for in Section 5.3.2 of this Rule, Interconnection Facilities connected directly to Electrical Corporation's Distribution System and Distribution System Improvements shall be provided, installed, owned and maintained by Electrical Corporation as Special Facilities.

5.3.3 **Third-Party Installations** Subject to the approval of Electrical Corporation, an Electricity Producer may, at its option, employ a qualified contractor to provide and install Interconnection Facilities or Distribution System Improvements to be owned and operated by Electrical Corporation. Such Interconnection Facilities and Distribution System Improvements shall be installed in accordance with Electrical Corporation's design and specifications. Upon final inspection and acceptance by Electrical Corporation, the Electricity Producer shall transfer ownership of such Electricity Producer installed Interconnection Facilities or Distribution System Improvements to Electrical Corporation and such facilities shall thereafter be owned and maintained by Electrical Corporation at Electricity Producer's expense as Special Facilities. The Electricity Producer shall pay the Electrical Corporation's reasonable costs of design, administration, and monitoring the installation of such facilities to ensure compliance with Electrical Corporation's requirements. Electricity Producer shall also be responsible for all costs, including any income tax liability, associated with the transfer of Electricity Producer installed Interconnection Facilities and Distribution System Improvements to Electrical Corporation.

5.3.4 **Reservation of Unused Facilities** When a Electricity Producer wishes to reserve Electrical Corporation-owned Interconnection Facilities or Distribution System Improvements installed and financed as Special Facilities for the Electricity Producer, but idled by a change in the operation of the Electricity Producer's Generating Facility or otherwise, Electricity Producer may elect to abandon or reserve such facilities consistent with the terms of its Interconnection Facility Financing and Operating Agreement with Electrical Corporation. If Electricity Producer elects to reserve idled Interconnection Facilities or Distribution System Improvements, Electrical Corporation shall be entitled to continue to charge Electrical Producer for the costs related to the ongoing operation and maintenance of the Special Facilities.

5.3.5 **Refund of Salvage Value** When a Electricity Producer elects to abandon the Special Facilities for which it has either advanced the installed costs or constructed and transferred to the Electrical Corporation, the Electricity Producer shall, at a minimum, receive from the Electrical Corporation a credit for the net salvage value of the Special Facilities.

6. METERING, MONITORING and TELEMETRY

6.1 **General Requirements** All Generating Facilities shall be metered in accordance with this Section 6 and shall meet all applicable standards of the Electrical Corporation contained in the Electrical Corporation's applicable tariffs and published Electrical Corporation manuals dealing with metering specifications. The requirements in this Section 6 do not apply to metering of Generating Facilities operating under the Electrical Corporation's net metering tariff pursuant to California Public Utilities Code Section 2827.

6.2 **Metering by non-Electrical Corporation Parties** The ownership, installation, operation, reading, and testing of metering for Generating Facilities shall be by the Electrical Corporation except to the extent that the CPUC has determined that all these functions, or any of them, may be performed by a non-Electrical Corporation as authorized by the CPUC.

{Unattributed comment, 040300: It has been suggested that DG could own meters in some instances, that meters that come with the DG may suffice in some instances and that, if necessary, the Electrical Corporation might sign non-disclosure agreements covering access to the information. -ed}

6.3 **Net Generation Metering / Point of Common Coupling Metering**

6.3a (Alternate language offered by PG&E, 040300) **Net Generation Metering** For purposes of monitoring Generating Facility operation for determination of standby charges and applicable non-bypassable charges as defined in Electric Corporation's tariffs, and for Distribution System planning and operations, the Electric Corporation shall have the right to specify the type, and require the installation of, Net Generation Metering. Net Generation Metering shall be at the Electricity Producer's expense and shall have the ability to record the profile of the Generating Facility's kW or kWh output.

6.3b (Alternate language offered by CAC/EPUC, 041000) **Point of Common Coupling Metering** For purposes of assessing UC charges for retail service, the Electricity Producer's Point of Common Coupling Metering shall be a bi-directional meter so that power deliveries to and from the Electricity Producer's site can be separately recorded. Alternately, the Electricity Producer may, at its sole option, require the Electric Corporation to install multi-metering equipment to separately record power deliveries to the Distribution System and retail purchases from the Electric Corporation. Such Point of Common Coupling Metering may be equipped with detents to prevent reverse registration.

{Coast Intelligen, 033000: Sec. 6.3. Delete. There is no justification for small-scale power production, wholly onsite, non-export, to have to report to utilities or the ISO how much power they are making. The interconnection Agreement itself tells the utility the size of the generator, so they can make planning decisions accordingly. This kind of monitoring would be an expensive burden unnecessarily placed on small distributed generation.}

6.4 **Telemetering**

6.4a (Alternate language offered by PG&E:) **Telemetering** If the nameplate rating of the Generating Facility is 500kW or greater, Telemetering equipment at the Net Generator Metering location will be required at the Electricity Producer's (and Customer's) expense. If the Generating Facility is interconnected to a Distribution System operating at a voltage below 10kV, then Telemetering equipment is required on Generating Facilities 100kW or greater.

6.4b (Alternate language offered by CAC/EPUC, 041000) **Telemetering** Point of Common Coupling Metering may include telemetry of the recorded data.

{Honeywell, 040100: Honeywell does not believe that separate measurement of the output of the producer's generator is necessary or should be required. Further, Honeywell does not support the second sentence in Section 6.4 that would allow UDC discretion in determining whether telemetering is necessary. Measurement and real-time telemetering and control may be appropriate requirements for DG units that are selling energy, capacity, or ancillary services in the market.}

{Enron 033100: Telemetry requirements by the UDCs need to be specified and justified with technical requirements. The inclusion of telemetric requirement for all Generation Facilities above1 MW and sometime necessary for smaller units needs to be demonstrated. }

{Coast Intelligen 033000:: Change requirement to telemeter for 4kV lines only for projects larger than 55 kW. PLEASE NOTE THAT BECAUSE WE HAVE NOT YET FULLY ANALYZED THE IMPLICATIONS OF SEC.4, TESTING AND SCREENING, ON OUR PARTICULAR PRODUCT, WE RESERVE COMMENT ON THE PROPOSED LANGUAGE. WE CONTINUE TO ASSUME THAT MUCH OF THE PROPOSED PROTECTIONS ARE NOT JUSTIFIABLE WHEN OUR PRODUCT IS EXAMINED.}

{Hetch Hetchy Water and Power 032900 6.4 Telemetering If the Generating Facility exports more than 1 MW, telemetering equipment may be required at the point of common coupling.}

6.5 **Location** Where Electrical Corporation-owned metering equipment is located on the Electricity Producer's (or Customer's) premises, Electricity Producer (and Customer) shall provide, at no expense to the Electrical Corporation, a suitable location for all such metering equipment.

6.6 **Costs of metering** The Electricity Producer (and Customer) will bear all costs of the metering required by this Rule 21, including the incremental costs of operating and maintaining the Metering.

{Hetch Hetchy Water and Power: 032900: 6.6 HHWP would like the following language reinserted: For circumstances where the Electrical Corporation provides retail service to the Producer, the Producer or Customer shall be responsible for only those incremental metering costs that exceed metering costs collected in the UDC's retail rates.}

7. DISPUTE RESOLUTION PROCESS

7.1 The CPUC shall have initial jurisdiction to interpret, add, delete or modify any provision of this Tariff Rule 21 or of any agreements entered into between the UDC and the Producer to implement this tariff ("the implementing agreements") and to resolve disputes regarding the UDC's performance of its obligations under the UDC's electric rules and tariffs, the implementing agreements, and requirements related to the interconnection of Producer's Facilities pursuant to this Tariff Rule 21.

7.2 Any dispute arising between the UDC and the Producer (individually "Party" and collectively "the Parties") regarding the UDC's performance of its obligations under the UDC's electric rules and tariffs, the implementing agreements, and requirements related to the interconnection of Producer's Facilities pursuant to this Tariff Rule 21 shall be resolved according to the following procedures.

7.2.1 The dispute shall be reduced to writing by the aggrieved Party in a letter ("the dispute letter") to the other Party containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the aggrieved Party that it is invoking the procedures under this Section 7.2. Within 45 calendar days of the date of the dispute letter, the Parties' authorized representatives will be required to meet and confer to try to resolve the dispute.

7.2.2 If the Parties do not resolve their dispute within 45 calendar days after the date of the dispute letter, the dispute shall, upon demand of either party, be submitted to resolution before the Commission in accordance with the Commission's rules, regulations and procedures applicable to the resolution of such disputes.

{Enron, 033100: Section 7.2.1 requires parties to meet and confer within 45 days of submitting the dispute letter. Section 7.2.3 states that if the parties cannot resolve their dispute within 45 days they can proceed accordingly. There should be a lag between the time the discussions begin and when the clock stops for the discussion. The parties could have to meet within 30 days of submitting the letter (a change from 45 days) and that if the dispute is not resolved within 45 days (giving 15 days for discussions) then they should proceed accordingly.}

7.3 Pending resolution of any dispute under this Section 7, the Parties shall proceed diligently with the performance of their respective obligations under this Rule 21 and the implementing agreements, unless the implementing agreements have been terminated.

7.4 Disputes as to the application and implementation of this Section 7 shall be subject to resolution pursuant to the procedures set forth in this Section 7.

8. DEFINITIONS

Active Anti-Islanding Scheme: A control scheme installed with the Distributed Generator that senses and prevents the formation of an Unintended Island.

Applicant: The entity submitting an Application for Interconnection.

Application: The standard form CPUC-approved document submitted to the Electrical Corporation for electrical interconnection of a Generator with the Electrical Corporation**.**

Certification Test; A test adopted by the Electrical Corporation that verifies conformance of certain equipment with CPUC-approved performance standards in order to be classified as Certified Equipment. Certification Tests are normally performed by approved laboratories such as the Underwriter's Lab (UL).
Certification; Certified: The results of successful Certification Testing.

Certified Equipment: Equipment that has passed the Certification Test.

CPUC: The Public Utilities Commission of the State of California.

Customer: The entity that receives or is entitled to receive Distribution Services through the Distribution System

Dedicated Transformer: A transformer that provides Electricity Service to a single Customer only. The Customer may or may not have a Generating Facility.

Distributed Generation: Electrical power generation by any means, including from stored electricity, that is Interconnected to an Electrical Corporation at a Point of Common Coupling under the jurisdiction of the CPUC.

Distributed Generator: An individual electrical power plant, including required equipment, appurtenances, protective equipment and structures, that is capable of Distributed Generation.

Distribution Service: All services required by, or provided to, a Customer pursuant to the approved tariffs and rules of the Electrical Corporation.

Distribution System Island: A condition on the Distribution System in which one or more Distributed Generator(s), over which the utility has no direct control, and a portion of the Distribution System operate while isolated from the remainder of the Distribution System.

Distribution System: All electrical wires, equipment, and other facilities owned or provided by the Electrical Corporation by which an Electrical Corporation provides Distribution Service to its Customers.

Electrical Corporation: The entity that, under the jurisdiction of the CPUC, is charged with providing Electricity Distribution Service to the Customer.

Electricity Producer: The entity that executes an Interconnection Agreement with the Electrical Corporation. The Electricity Producer may or may not own or operate the Distributed Generator, but is responsible for the rights and obligations related to the Interconnection Agreement.

Emergency: An actual or imminent condition or situation, which jeopardizes the Distribution System Integrity.

Field Testing: Testing performed in the field to determine whether equipment meets the Electrical Corporation's requirements for safe and reliable Interconnection

Generating Facility: All the Distributed Generators, that are included in an Interconnection Agreement.

Gross Nameplate Rating: The total gross generating capacity of the Distributed Generator as designated by the manufacturer of the Distributed Generator..

Host Load: Electrical power that is consumed by the Customer at the property on which the Generating Facility is located.

Initial Operation: The first time the Generating Facility is in Parallel Operation.

Initial Review: The review by the Electrical Corporation, following receipt of an Application, to determine the following:

a. If an Application qualifies for Simplified Interconnection, or
b. If an Application can be made to qualify for Interconnection with supplemental review determining any potential additional requirements, or
c. If an Interconnection Study is required, the cost estimate and schedule for performing the Interconnection Study

Interconnection Agreement: An agreement between the Electrical Corporation and the Electricity Producer that gives each the certain rights and obligations to effect or end Interconnection.

Interconnection Study: A study to establish the requirements for Interconnection of an Electricity Producer.

Interconnection; (Interconnected): The physical connection of Distributed Generation in accordance with the requirements of these rules so that Parallel Operation with the utility system can occur (has occurred).

Island; Islanding: A condition on the Distribution System in which one or more Distributed Generator(s), deliver power to Customers using a portion of the Distribution System that is electrically isolated from the remainder of the Distribution System.

ISO: The California Independent System Operator, responsible for the management of electrical power flow through California's electrical transmission network.

Line Section: That portion of the Distribution System connected to a Customer bounded by automatic sectionalizing devices or the end of the line.

Load Balance Ratio: The ratio of the Net Nameplate Rating of the Distributed Generator to the total capability of the Distribution System to deliver power to the Electricity Producer at the Point of Common Coupling.
Metering Equipment: All equipment, hardware, software including meter cabinets, conduit, etc. that is necessary for Metering.

Metering: The measurement of electrical power flow in kW and/or kWh at a point, and its display to the Electrical Corporation, as required by this rule.

Net Energy Metering: The mutual purchase and sale of electricity between the Electricity Producer and the Electrical Corporation pursuant to the net metering tariff approved by the CPUC.

Net Generation Metering: The Metering of the net electrical energy output in kW and kWh from a given Distributed Generator. This may also be the measurement of the difference between the total electrical energy produced by a Distributed Generator and the electrical energy consumed by the auxiliary equipment necessary to operate the Distributed Generator. For a Distributed Generator with no Host Load and/or

Section 218 Load, Metering that is located at the point of Common Coupling. For a Distributed Generator with Host Load and/or Section 218 Load, Metering that is located at the Distributed Generator bus after the point of auxiliary load(s) and prior to serving Host Load and/or Section 218 Load.

Net Metering: Where electricity at a point may flow in both directions, the measurement of the net, or the algebraic sum, of electrical energy in kWh, that flows through that point in a given time-interval. Net Metering typically uses two meters, or in some cases a single meter with two or more registers, to individually measure a Customer's electric deliveries to, and consumption of retail service from, the Distribution System. Over a given time frame (typically a month) the difference between these two values yield either net consumption or net surplus. The meter registers are ratcheted to prevent reverse registration. If available, a single meter may be allowed spin backward to yield the same effect as a two meter (or register) arrangement.

Net Nameplate Rating: The Gross Nameplate Rating minus the consumption of electrical power of the Distributed Generator as designated by the manufacturer(s) of the Distributed Generator.

Network Service: More than one electrical feeder providing Distribution Service at a Point of Common Coupling.

Parallel Operation: The simultaneous operation of a Distributed Generator with power delivered or received by the Electrical Corporation while Interconnected. For the purpose of this rule, Parallel Operation includes only those generators that are so interconnected with the Distribution System for more than 60 cycles.

Point of Common Coupling Metering: Metering located at the Point of Common Coupling. This is the same Metering as Net Generation Metering for Generating Facilities with no Host Load and/or Section 218 Load.

Point of Common Coupling: The transfer point for electricity between the electrical conductors of the Electrical Corporation and the electrical conductors of the Electricity Producer.

Point of Interconnection: The electrical transfer point between an electrical power plant and the electrical distribution system. This may or may not be coincident with the Point of Common Coupling.

Power Purchase Agreement: An agreement for the sale of electricity by the Electricity Producer to the Electrical Corporation.

Protective Function(s): The equipment, hardware and/or software in a Generating Facility (whether discrete or integrated with other functions) whose purpose is to protect against Unsafe Operating Conditions.

Prudent Electrical Practices: Those practices, methods, and equipment, as changed from time to time, that are commonly used in prudent electrical engineering and operations to design and operate electric equipment lawfully and with safety, dependability, efficiency, and economy.

Scheduled Operation Date: The date specified in the Interconnection Agreement when the Generating Facility is, by the Electricity Producer's estimate, expected to begin Initial Operation.

Secondary Network: A network supplied by several primary feeders suitably interlaced through the area in order to achieve acceptable loading of the transformers under emergency conditions and to provide a system of extremely high service reliability. Secondary networks usually operate at 600 V or lower.

Section 218 Load: Electrical power that is supplied in compliance with California Public Utilities Code (PU Code) section 218. PU Code 218 defines an "Electric Corporation" and provides conditions under which a generator transaction would not classify a generating entity as an Electric Corporation. These conditions relate to "over-the-fence" sale of electricity from a generator without using the Distribution System.

Simplified Interconnection: Interconnection conforming to the minimum requirements under these rules, as determined by Appendix A "Method for Screening Applications".

Stabilization; Stability: The return to normalcy of an Electrical Corporation Distribution System, following a disturbance. Stabilization is usually measured as a time period during which voltage and frequency are within acceptable ranges.

System Integrity: The condition under which a Distribution System is deemed safe and can reliably perform its intended functions in accordance with the safety and reliability rules of the Electrical Corporation.

Telemetering: The electrical or electronic transmittal of Metering data on a real-time basis to the Electrical Corporation.

Unintended Island: The creation of an island, usually following a loss of a portion of the Distribution System, without the approval of the Electrical Corporation.

Unsafe Operating Conditions: Conditions that, if left uncorrected, could result in harm to personnel, damage to equipment, loss of System Integrity or operation outside pre-established parameters required by the Interconnection Agreement.

Rule 21 Appendix A: Initial Review Process for Applications to Interconnect Distributed Generation

Introduction:

This Initial Review Process was developed to create a path for selection and rapid approval of those Applications for Interconnection that do not require an Interconnection Study. The capitalized phrases used in this Appendix A have the same meanings as those in Section 8 of the proposed Rule 21.

Purpose:

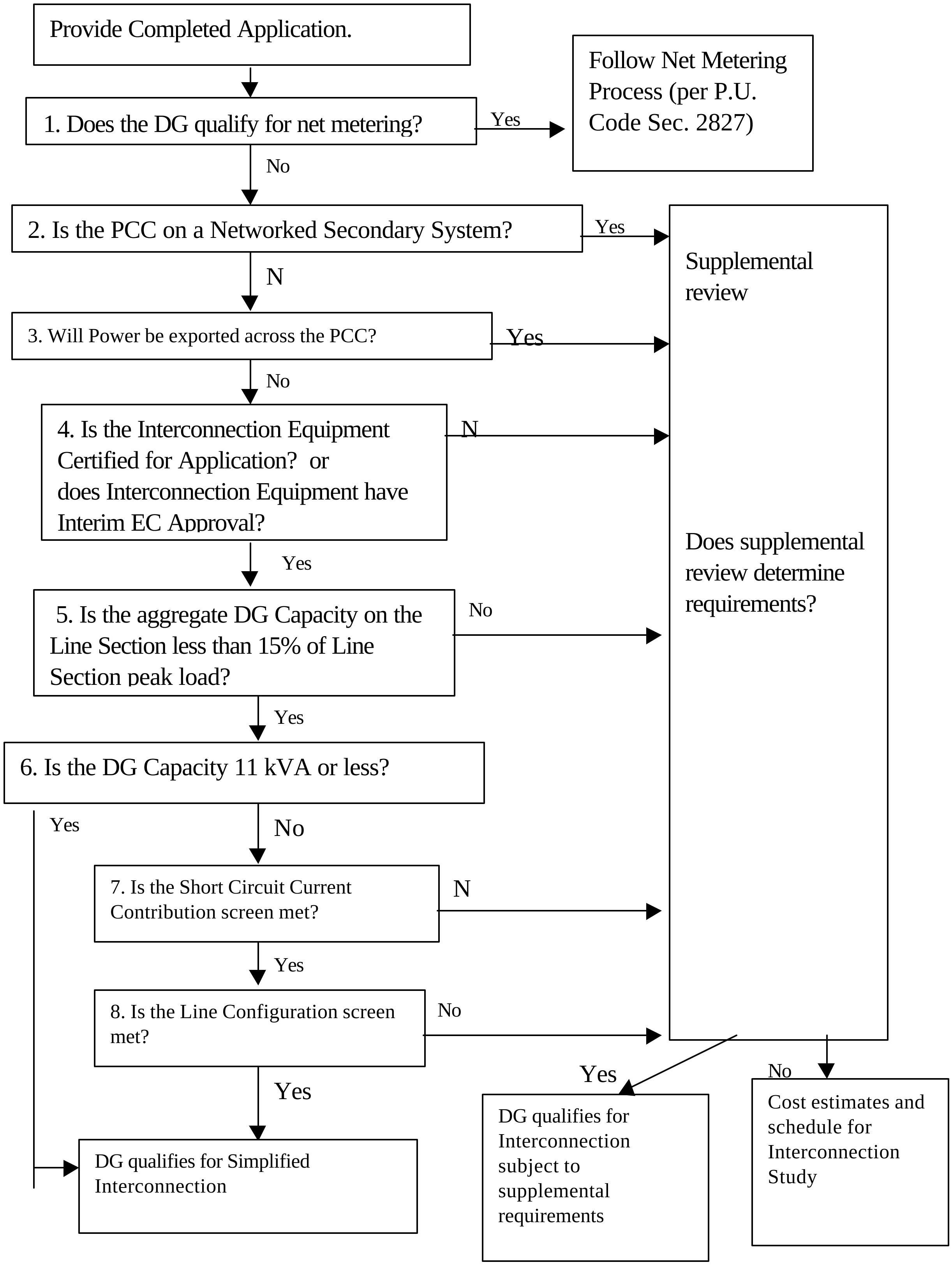
The Initial Review determines:

a. If an Application qualifies for Simplified Interconnection;
b. If an Application can be made to qualify for Interconnection with supplemental review determining any potential additional requirements, or
c. If an Interconnection Study is required, the cost estimate and schedule for performing the Interconnection Study.

Note:

Failure to pass any screen only means that further review, and/or studies, are required before the DG project will be approved for interconnection with the Electrical Corporation. It does not mean that the DG cannot interconnect.

Initial Review Process Flow Chart



Initial Review Process Details:

1. Does the DG qualify for net metering?

If YES, go to a separate process for net-metered DG (per P.U. Code Sec. 2827)
If NO, continue to next screen.

Significance:

1. Net-metered systems are covered by state legislation.
   Refer to Section 2827 of Public Utilities Code.

Criteria to Qualify for Net-Metering:

1. DG facility must comply with PUC Code Section 2827

2. Is the PCC on a Networked Secondary System?

If NO, continue to next screen.
If YES, DG does not qualify for Simplified Interconnection.
Perform supplemental review.

Significance:

1. Special considerations must be given to DG on networked secondary distribution systems because of the design and operational aspects of network protectors. There are no such considerations for radial distribution systems.

3. Will power be exported across the PCC?

If YES, DG does not qualify for Simplified Interconnection.
Perform supplemental review.

If NO, DG must incorporate one of the following four options:

Option 1:
To insure power is never exported, a reverse power Protective Function must be implemented at the PCC.
Default setting shall be 0.1% (export) of transformer rating, with a maximum 2.0 second time delay.

Option 2:
To insure at least a minimum import of power, an under-power Protective Function must implemented at the PCC.

Default setting shall be 5% (import) of DG Gross Nameplate Rating, with maximum 2.0 second time delay.

Option 3:
To limit the incidental export of power, all of the following conditions must be met:
- The aggregate DG capacity of the Generating Facility must be no more than 25% of the nominal ampere rating of the Customer's Service Equipment;
- The total aggregate DG capacity must be no more than 50% of the transformer rating (This capacity requirement does not apply to customers taking primary service without an intervening transformer);
- The DG must be certified as non-islanding.

Option 4:
To insure that the relative size (capacity) of the DG compared to facility load results in no export of power without the use of additional devices, the DG capacity must be no greater than 50% of the customer's verifiable minimum annual load.

Significance:

1. Electrical Corporation's system does not need to be studied for load-carrying capability or DG power flow effects on EC voltage regulators since on-site DG reduces EC load.
2. Permits use of reverse-power relaying at the PCC as positive anti-islanding protection.

4. Is the Interconnection Equipment Certified for the Application or does the Interconnection Equipment have Interim EC Approval?

If NO, DG does not qualify for Simplified Interconnection.
Perform supplemental review.

If YES, continue to next screen.

Significance:

The Electrical Corporation does not need to review, or test, the DG's protective function scheme. Site commissioning testing may still be required to insure that the system is connected properly and that the protective functions are working properly.

- Basic protective function requirements met.
- Harmonic distortion limits met.
- Synchronizing requirements met.
- Flicker limitation requirements met.

- Pf regulation requirements met.
- Non-islanding requirements met.
- If used, reverse power function requirement met.
- If used, under-power function requirement met.

5. Is the aggregate DG Capacity on the Line Section less than 15% of Line Section Peak Load?

If YES, continue to next screen.
If NO, perform supplemental review to determine cumulative impact on Line Section.

Significance:

1. Low penetration of DG will have a minimal impact on operation and load restoration.

6. Is the DG Capacity 11 kVA or less?

If Yes, DG qualifies for Simplified Interconnection.
If No, continue to next screen.

Significance:

1. DG has minimal impact on fault current levels and any potential line overvoltages from loss of system neutral grounding.

7. Is Short Circuit Current Contribution screen met?

If NO, DG does not qualify for Simplified Interconnection.
Perform supplemental review.

If YES, continue to next screen.

Short Circuit Current Contribution Screen:

A. At primary side (high side) of dedicated distribution transformer, for the specified feeder, the sum of the Short Circuit Contribution Ratios (SCCR) of all DG's on the feeder must be less than or equal to 0.1.

B. At secondary (low side) of a shared distribution transformer, the short circuit contribution of the proposed DG must be less than or equal to 2.5% of the interrupting rating of the Customer's Service Equipment.

<u>Significance</u>:

No significant DG impact on:

- Distribution System's short circuit duty
- Distribution System fault detection sensitivity
- Distribution System relay coordination
- Distribution System fuse-saving schemes

8. Is the Line Configuration screen met?

If NO, then DG does not qualify for Simplified Interconnection.
Perform supplemental review.

If Yes, then DG qualifies for Simplified Interconnection.

Line Configuration Screen:

Identify primary distribution line configuration. Based on proposed interconnection type, determine from table whether DG passes screen.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	Any	Pass screen
Three-phase, four wire	Single-phase, line-to-neutral	Pass screen
Three-phase, four wire (For any line that has such a section OR mixed 3 wire & 4 wire)	All others	To pass, aggregate DG Capacity must be less than or equal to 10% of Line Section Peak Load.

Significance:

1. If the Electrical Corporation's primary system is three-wire or the DG interconnection transformer is single-phase (line-to-neutral), then there is no concern about overvoltages to the Electrical Corporation's, or Customer, equipment caused by loss of system neutral grounding during the operating time of anti-islanding protection.

Rule 21 Appendix B: Testing and Certification

Comments provided by
[AK] - Alex Kim, So Cal Gas
[CMW] – Chuck Whitaker, Endecon Engineering (Subgroup coordinator)
[DCD] - Doug Dawson, SCE
[DR] – David Redding, City of Riverside
[NERC] - NERC
[PP] - Plug Power

This Appendix describes the test procedures and requirements for interconnection Distributed Generation equipment to the Electric Corporation's distribution system. Included are Type Testing, Production Testing, Commissioning Testing, and Periodic Testing. Equipment certified by an accredited, nationally recognized testing laboratory as having met both the Type Testing (B1) and Production Testing (B2) requirements are considered Certified Equipment for purposes of interconnection. It relies heavily on the procedures described in appropriate UL, IEEE, and IEC documents—most notably UL 1741 and IEEE 929—as well as the testing described in May 1999 New York Standardized Interconnection Requirements.

Due to time and resource constraints and the priority given to the Technical Section and Appendix A, this appendix has not received the level of review and comments necessary to provide a complete draft meeting workgroup consensus. While it does represent a significant step in the process, there are remaining issues to be resolved and procedures to be developed or finalized. As such, it remains a work in progress.

Type testing:
Inverters
Static power inverters shall meet all of the type tests and requirements appropriate for a utility interactive inverter as specified in UL 1741 *Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems*, and listed below. These requirements may be applied to inverters used with DG sources other than PV. Note that the specific section number from the May 1999 version of UL1741 is provided for each test and requirement. The titles for some sections were added for clarity. These section numbers are subject to change by UL.

[AK: The way this is written, it implies "ALL inverters MUST to be certified" rather than, "to be certified, and inverter must be certified by a nationally recognized lab". I recognize this falls under the section of Type Testing and therefore it should be implied the latter statement is true, but I think we should clarify the statement.]

[CMW: Article 690-60 of the NEC says:
"Only inverters and ac modules listed and identified as interactive shall be permitted in interactive systems".

I am told that 691, the newly proposed article for fuel cells will be written similarly. Below, I have specified the relevant tests and support paragraphs from UL1741 that I think are required for utility interactive inverters.]

39.1	Utility Disconnect Switch
39.2	Field Adjustable Trip-points39.3 Field Adjustable Trip-points
39.4	Field Adjustable Trip-points
39.5	Field Adjustable Trip-points, Marking
40.1	DC Isolation
41.2	Simulated PV Array requirements
44	Dielectric Voltage Withstand Test
45.2.2	Power Factor
45.4	Harmonic Distortion
45.5	DC Injection
46.2	Utility Voltage and Frequency Variation Test
46.2.3	Reset Delay
46.4	Loss of Control circuit
47.2	Output Overload Test
47.3	Short Circuit Test
47.7	Load Transfer Test
53	Voltage Surge
54	Calibration test
55	Overvoltage Test
56	Current Withstand Test

A description of key aspects of these procedures is provided in Appendix C.

In addition, to be considered non-exporting, inverters shall be certified by an accredited, nationally recognized testing laboratory as having passed the non-export test procedure in Appendix C.

Synchronous Devices
No interconnection test standards have been identified for synchronous machines. It is likely that some combination of UL 2200 and UL 1741 will be the basis for a standardized test procedure.

Until a suitable standard is identified, an accredited nationally recognized test laboratory can perform the appropriate tests described in Appendix C1 to certify the performance of the control system functions of the synchronous machine.

Induction Devices
No interconnection test standards have been identified for induction machines. It is likely that some combination of UL 2200 and UL 1741 will be the basis for a standardized test procedure.

Until a suitable standard is identified, an accredited nationally recognized test laboratory can perform the appropriate type tests described in Appendix C1 to certify the performance of the control system functions of the induction machine.

[CMW: Need to add a flicker test here.]

Anti-Islanding Test

In addition to the above type tests, devices that pass the Anti-Islanding test procedure described in Appendix C2 will be considered Non Islanding for the purposes of these interconnection requirements.

Non Export Test

In addition to the above type tests, devices that pass the Non-Export test procedure described in Appendix C3 will be considered Non Exporting for the purposes of these interconnection requirements.

Production Testing

As a minimum, the Production Test procedures described in Appendix C4 shall be performed as part of routine production (100%) on all equipment used to interconnect DG to EC. These requirements are intended to be the same as those specified in UL1741 Manufacturing and Production Tests, sections 67 and 68.

Commissioning Testing

Commissioning testing will be performed on-site to verify protective settings and functionality. Upon initial parallel operation of a generating system, or any time interface hardware or software is changed, a verification test must be performed. An individual qualified in testing protective equipment (professional engineer, factory-certified technician, or licensed electrician with experience in testing protective equipment) must perform verification testing in accordance with the manufacturer's published test procedure. The utility reserves the right to witness verification testing or require written certification that the testing was performed.

Testing to be performed during commissioning may consist of the following:

- Over- and under-voltage
- Over- and under-frequency
- Anti-Islanding function (if applicable)
- Non-Export function (if applicable)
- Inability to energize dead line
- Time delay restart after utility source is stable
- Directional power (if used)
- Utility system fault detection (if used)
- Synchronizing controls (if applicable)
- Verify final protective settings

Systems Qualifying for Simple Interconnection

Systems qualifying for simple interconnection incorporate Certified Equipment that have, at a minimum, passed the type and production tests described in this document, and are judged to have little or no potential impact on the EC distribution system. For such systems, it is only necessary to certify the following:

- field-adjusted settings (where applicable, i.e. factory-tested settings do not require re-testing in the field). Tests will be performed using injected secondary quantities (voltage or current). If secondary injection is not possible (e.g., inverter system), tests must be conducted to verify protective operation using 1) applied waveforms, 2) a test connection using a generator to simulate abnormal utility voltage or frequency, or 3) varying the setpoints to show that the device trips at the measured (actual) utility voltage or frequency.
- Non-Islanding function by operating the load break disconnect switch to verify the interconnection equipment ceases to energize the line and does not re-energize for the required time delay after the switch is closed
- Non-Export function by adjusting the DG output and local loads to verify that the applicable non-export criteria (i.e., reverse power or under power) are met.

Systems Not Qualifying for Simple Interconnection

Certified Equipment

Systems using certified equipment but that do not qualify for simple interconnection are required to meet the requirements of Section B3.1 and additional tests as agree to by the supplier and Electrical Corporation. These additional tests will verify the equipment, capabilities, or settings that were necessary to allow interconnection.

Non-certified equipment

Calibration tests for all protective devices, including multiple tests for multifunction packages, will be required. Tests will be performed using injected secondary quantities (voltage and/or current). If secondary injection is not possible (e.g. inverter system), tests must be conducted to verify protective operation using either applied waveforms or a test connection using a generator to simulate abnormal utility voltages. Exception: Single-phase inverters rated 10kW and below may be verified by operating the load-break disconnect switch and verifying the unit ceases to energize the line. Functional tests must prove trip outputs to the appropriate circuit breakers, or, in the case of inverter systems, must prove that the inverter system will cease to energize the line. Where breakers are used for isolation, breaker timing tests will be required. Upon completion of all testing, application of the final settings will be verified.

[CMW: per Robert Wichert, should the commissioning test section specifically exclude harmonics testing or should we suggest when it might need to be performed, especially in this non-certified section? Also, do we want to simply state that non-certified equipment must be tested according to the procedures provided in Appendix C1, or otherwise show that it meets all those requirements? That presumes these commissioning tests will be the only tests performed on this equipment]

Periodic Testing

Periodic testing shall be performed every four years. All periodic tests prescribed by the manufacturer shall be performed. If wires must be removed to perform certain tests, each wire and each terminal must be clearly and permanently marked. The generator-owner shall maintain periodic test reports for inspection by the connecting utility.

Single phase inverters rated 10kW or below may be verified once per year as follows: once per year, the owner or his agent shall operate the load break disconnect switch and verify the interconnection equipment ceases to energize the line and does not re-energize for five minutes after the switch is closed. The owner shall maintain a log of these operations for inspection by the connecting utility.

A system that depends upon a battery for trip power shall be checked and logged once per month for proper voltage. Once every four (4) years, the battery must be either replaced of a discharge test performed.

> [PP - The Periodic Testing section acknowledges that it was lifted directly from the NYS Standards Interconnection Requirements. But it appears to have lifted them from an earlier version of the standard. The final cutoff point that was reached in New York as the point at which an inverter is considered "small" is 15 kVA, not 10 kW as is being proposed in California. We argued with the Public Service Commission that the number should actually be 50 kW in order for it to be consistent with NFPA 853 (the stationary fuel cell installation standard). After all, why should a 12 kW fuel cell inverter be treated like those being provided for 250 kW fuel cell power plants rather than like those being provided for 10 kW Photovoltaic systems? Note also that the 10 kW number comes from the fact that that is the value specified in IEEE P929. But the 10 kW number is not based upon any electrical limits that might be exceeded beyond 10 kW. 10 kW was established as the limit in P929 because it was felt that that would be the largest photovoltaic system that could be feasibly installed on the rooftop of a residential dwelling. Trust me, we have no intent our installing our fuel cell systems on top of any roofs. The number at which inverters are considered "small" should be based upon electrical considerations; not on P929. Again, we would recommend 50 kW as the cutoff point.]

> [AK - If we are trying to stay away from size limitations, there should not be one for this section unless there is a compelling reason.]

Type Test Procedures

Type Test

This section describes the Type tests that are necessary to qualify a device as Certified. These procedures are provided as a convenience for those manufacturers that have not obtained a copy of Underwriters Laboratories UL 1741 Standard *Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems*. The descriptions include the section numbers from the May 1999 version of UL1741. The titles for some sections are not included in UL 1741 but were added here for clarity. Also, section numbers are subject to change by UL. Note that this section is subject to review by UL for copyright infringement issues.

UL 1741-39.1 Utility Disconnect Means

Requires the inverter have an automatic disconnect to cease and automatically or manually resume power to the utility in compliance with the Voltage and Frequency Variation test. Inverters larger than 10kW may have a separate disconnect device if it is appropriately marked.

UL 1741-39.2 - 39.5 Field Adjustable Trip-points

States that inverters may have field-adjustable set points provided they are accessible to service personnel only, trip times and adjustment ranges are described in the manual, and the unit is appropriately marked.

UL 1741-40.1 and 45.5 DC Isolation

Requires that the inverter limit dc to the utility to no greater than 0.5% of the rated inverter output, or be marked as requiring an isolation transformer.

UL 1741-41.2 and 41.3 Simulated PV Array and utility requirements

UL 1741 states that the inverter is to be supplied by a device that simulates the current-voltage characteristics and time response of a photovoltaic array, with tests performed and max and min rated input voltages. This requirement is modified here such that the supply simulates the current-voltage characteristics and time response of a photovoltaic array, fuel cell, microturbine, or other intended input source.

Also requires that the simulated utility, if used must have an impedance of less than 5 percent of the inverter output impedance.

UL 1741-44 Dielectric Voltage Withstand Test

Specified as 1 minute a 1000V + 2x Max voltage

UL 1741-45.2.2 Power Factor

Requires a minimum output power factor of 0.85 at 100% of rated power. Unit is also tested at 25 and 50% though no requirements are specified for these levels.

UL 1741-45.4 Harmonic Distortion

Inverter must meet IEEE 519 requirements, a THD (current) of less than 5%, individual odd current harmonic limits shown below, and individual even current harmonics less than 25% of that shown for the odd harmonics in the same range. Measurements made at 100% of rated output into a simulated utility with less than 2% voltage distortion

Odd harmonics	Distortion limit (percent)
3rd through 9th	less than 4.0
11th through 15th	less than 2.0

17th through 21st	less than 1.5
23rd through 33rd	less than 0.6
above the 33rd	less than 0.3

UL 1741-46.2 Utility Voltage and Frequency Variation Test

The inverter shall disconnect from the utility after the simulated utility voltage and current are adjusted to the values shown in the table below. Each condition shall be repeated 10 times. Inverter is not required to be run at full power. Three phase inverters shall disconnect all three phases when any individual phase voltage goes outside the ranges specified below.

For units with field adjustable trip points, each trip point is to be set and tested in accordance with the table below. In addition, the adjustable trip points are to be set and tested for the voltage and frequency range and specified trip time as detailed in the manufacturer's installation instructions.

Disconnect limits for utility interaction

Condition	Simulated utility source		Maximum time before disconnect[a]	
	Voltage (V)	Frequency, Hz	Seconds	Cycles
A	$< 0.50\ V_{nor}$[b]	rated	0.1	(6)
B	0.50 Vnor ≤ V < 0.88 Vnor	rated	2	(120)
C	0.88 Vnor < V < 1.10 Vnor	rated	[c]	[c]
D	1.10 Vnor < V < 1.37 Vnor	rated	2	(120)
E	1.37 Vnor ≤ V	rated	0.03	(2)
F	rated	f >60.5	0.1	(6)
G	rated	f <59.3	0.1	(60)

[a] When a utility frequency other than 60 Hz is use90
d for the test, the maximum disconnect time shall not be longer than the time for a utility frequency of 60 Hz regardless of the number of cycles that occur before disconnection.

[b] Vnor is the nominal output voltage rating.

[c] No disconnect is required.

UL 1741-46.2.3 Reset Delay

Following each disconnection test, the simulated utility source's voltage and frequency are to be restored to the rated output voltage and frequency for the unit. An inverter provided with manual reset control shall remain disconnected from the simulated utility source. An inverter with an automatic reset control shall remain disconnected until the utility voltage and frequency have been restored for at least ??? seconds. The reset delay needs to be tested only once, after which a shorter delay may be used to facilitate rapid testing.

UL 1741-46.4 Loss of Control circuit

The inverter shall cease power production to the utility until the control circuit regains power when a single fault is to be placed such that it disables the power to the control circuit.

UL 1741-47.2 Output Overload Test
Connect the input to a source capable of twice the inverter's rated input current. Adjust the utility voltage to provide maximum output current. Operate the unit until it shuts down, reaches thermal equilibrium, or for 7 hours, whichever comes first.

UL 1741-47.3 Short Circuit Test
Disconnect the unit from the utility and immediately short the output line-to-neutral or ground and line-to-line, when applicable (phase to neutral or ground and phase to phase for 3 phase). Record the maximum inverter output fault current immediately after the short is applied. Apply the short before any external transformer.

UL 1741-47.7 Load Transfer Test
Connect a by-pass AC source (out of phase with the ac output of the inverter 120 degrees for 3 phase, 180 degrees for 1 phase) to one side of the load transfer switch, and the invert to the other side.

[CMW – Is this appropriate and necessary for our interconnection work?]

UL 1741-53 Voltage Surge
Units with ground fault detection functions are preconditioned at 32C, 93%RH for 168 hours for outdoor rated units or 48 hours for others. The unit is then subjected to

- 6kV surge impulse ten times at 60-second intervals (interrupter may trip)

followed by

- 3kV surge impulse ten times at 60-second intervals (interrupter shall not trip)

The ten impulses are applied randomly with respect to phase of the simulated utility ac voltage.

- Surge generator = 50 ohm surge impedence.

No load surge waveform:

- Initial rise – 0.5 ìsec between 10% and 90% of peak amplitude
- Period following oscillatory wave - 10 ìsec
- Each successive peak 60% of the preceding peak

Following surge test, unit shall comply with the Calibration Test (54)

UL 1741-54 Calibration test

Operating time of a ground fault detector/interrupter shall not exceed the time indicated in the table below with the current as described in the following and under each of these conditions:

a) As received in a 25 ±3.0°C (77.0 ±5.4°F) ambient,

b) Immediately following conditioning 48 hours in 85 ±5 percent relative humidity at 32 ±2.0°C (89.6 ±3.6°F),

c) After 4 hours in 40 ±2.0°C (104 ±3.6°F) ambient,

d) After 5 cycles of thermal shock consisting of 4 hours at 40 ±2.0°C (104 ±3.6°F) followed by 4 hours at 0 ±2.0°C (32 ±3.6°F) for general use equipment or 4 hours at 66 ±2.0°C followed by 4 hours at -35 ±2°C for outdoor use equipment, and

e) At 25 ±3.0°C (77,0 ±4.5°F).

Operating time

Ground-fault current, amperes	Time, seconds
115 percent of pickup	shall ultimately trip
150 percent of pickup	2.0
250 percent of pickup	1.0

The delay in operating time (and tolerance) indicated on the ground-fault detector / interrupter current relaying device shall be tested under all conditions listed here

In determining the operating time (including delay) under the above environmental conditions the test is to be performed at the end of the specified exposure time while the device is still in the test environment.

The interrupter is to be tested three times under each test condition with the test circuit set to deliver the required ground fault current. After the test current is applied to the interrupter sensor, record the time required for the interrupter relaying device to operate. When the interrupter is intended to be connected to a separate source of control power, the control voltage is to be adjusted to its rated value.

Set the field pick up current adjustment to its maximum value.

When power from a control power source is required to operate the device, repeat the above tests with the ground fault detector / interrupter connected to 55 percent of its rated voltage for ac control power and 80 percent of its rated voltage for dc control power.

Operation of a ground fault detector / interrupter shall not result in the tripping of the circuit interrupter on ground fault currents less than 85 percent of the pickup current trip limit of the ground fault sensing and relaying device.

UL 1741-55 Overvoltage Test

If the ground fault detector / interrupter is intended to be continually connected to a control voltage is shall be capable of withstanding 110% of rate control voltage without damage. The device shall also pass the dielectric test in (44)

UL 1741-56 Current Withstand Test

Subject ground fault detector/interrupter to a high fault current created by any number of turns in the sensor "window" producing the required ampere turn value and its withstand rating (current and time). The device shall subsequently comply with the requirements of Calibration Test, Section 53, as received in a 25 ±3.0°C (77.0 ±5.4°F) ambient).

Anti-Island Test Procedure

The text shown below was pulled from IEEE P929 Draft 11c. It is an improvement over what is in the current UL1741 (May 1999).

Once the fixed frequency and voltage limits have been verified, test to determine the inverter cannot maintain stable operation without the presence of a utility source. A utility source means any source capable of maintaining an island within the recommended voltage and frequency windows. An engine-generator with voltage and frequency control and with no anti-islanding protection is considered a utility source for the purpose of this test. However, because of the uncertainty associated with the need to sink both real and reactive power from the inverter, this test may be performed most conveniently with a utility connection, rather than a simulated utility. This test should be conducted with voltage and frequency near the middle of their operating ranges. Voltage should be at least 3% inside the most restrictive voltage trip limits. Frequency should be at least 0.25 Hertz inside the most restrictive frequency trip limits. (Note that frequency and voltage variation are not required for this testing.)

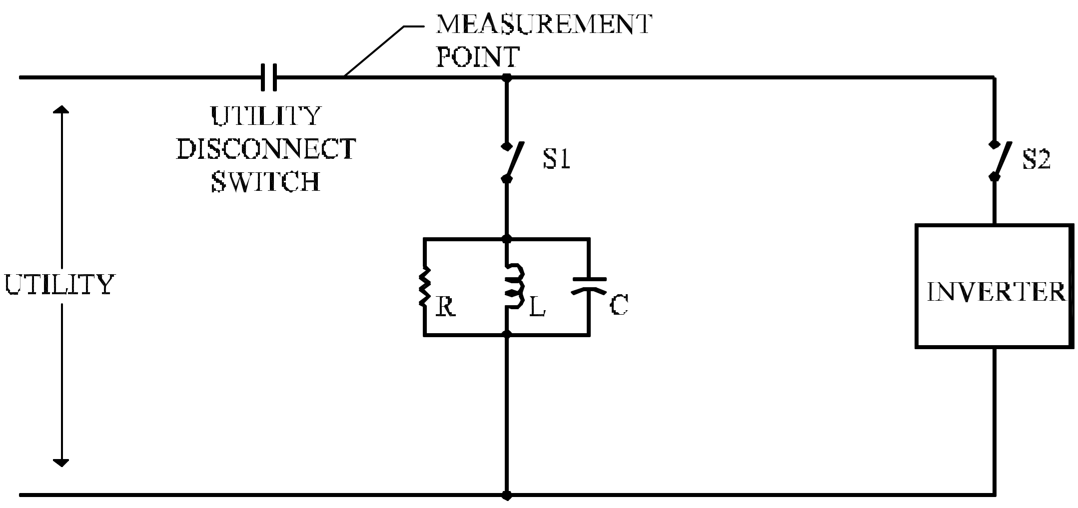


Figure C.1 Non-islanding inverter test circuit

This test procedure is based on having the Q of the islanded circuit (including load and generator) set equal to 2.5, where

$$Q = (1/P)\sqrt{P_{qL} \times P_{qC}}$$

Note also that, in the resonant case

$P_{qL} = P_{qC} = P_q$

Therefore, in the resonant case,

$Q = P_q / P$.

These formulas apply to the unity-power-factor inverter.

Test procedure background: This test procedure is designed to be universally applicable to both unity-power-factor inverters and non-unity-power-factor inverters. With unity-power-factor inverters, the second step, where $P_{q\text{-inverter}}$ is measured, will result in a value of $P_{q\text{-inverter}}$ that is zero, simplifying the remainder of the procedure. For inverters where $P_{q\text{-inverter}}$ is not zero the test is complicated by the presence of reactive power in the inverter.

Harmonic currents by the utility to the capacitor and the inverter, further complicating the situation by making it appear that current is flowing when the 60 Hz component of current has been zeroed. Thus, it is important, when adjusting inductive and capacitive reactance, to use instruments that can read only the 60Hz component of current and power.

The sequence of the steps below is suggested for several reasons. The inductance is measured first because that measurement is low in harmonics. The capacitance is added second so that the voltage is stable when the resistance is added. The resistive parallel load is then added and adjusted. Note that this resistance will be in addition to the resistance that will be part of the inductive load.

This test procedure assumes that a non-unity-power-factor inverter will be sourcing, not sinking, reactive power. The procedure refers to a circuit that is configured as shown in Figure C.1. Details of this circuit may be changed to suit the specific hardware available to the tester. For example, it may be convenient to replace switch S1 with individual switches on each leg of the RLC load. For each inverter/load power combination the following procedure is suggested to achieve the proper generation-to-load complex power balance.

Test Procedure:

a) Determine inverter test output power, P_{inv}, that will be used.
b) Operate the inverter at Pinv and measure inverter reactive power output, Pq-inverter. The utility disconnect switch should be closed. With no local load connected (that is, S1 is open so that the RLC load is not connected at this time), and

the inverter connected to the utility (S2 is closed), turn the inverter on and operate it at the output determined in step a). Measure real and reactive power flow at the measurement point. The real power should equal P_{inv}. The reactive power measured in this step is designated $P_{q\text{-}inverter}$.

c) Turn off the inverter and open S2.

d) Adjust the RLC circuit to have Q = 2.5. This is accomplished by:
   1) Determining the amount of inductive reactance required in the resonant RLC circuit using the relation $P_{qL} = 2.5\ P_{inv}$.
   2) Connecting an inductor as the first element of the RLC circuit and adjusting the inductance to P_{qL}.
   3) Connecting a capacitor in parallel with the inductor. Adjust the capacitive reactance so that $P_{qC} = P_{qL} - P_{q\text{-}inverter}$.
   4) Connecting a resistor that results in the power consumed by the RLC circuit equaling P_{inv}.

e) Connect the RLC load configured in step d) to the inverter by closing S1. Close S2 and turn the inverter on, making certain that the power output is as determined in step a).

   (**Note**: The purpose of the procedure up to this point is to zero out the 60 Hertz components of real and reactive power, or to zero out the 60 Hertz component of current flow, at the utility disconnect switch. System resonances will typically generate harmonic currents in the test circuit. These harmonic currents will typically make it impossible to zero out an RMS measurement of power or current flow at the disconnect switch. Because of test equipment measurement error and some impact from harmonic currents, it is necessary to make small adjustments in the test circuit to achieve worst case islanding behavior. Step g) is performed to make these small adjustments.)

f) Open the utility-disconnect switch to initiate the test.

g) After each successful test, one parameter is adjusted by approximately 1.0%per test, within a total range of ±5% of the operating point determined in step d) above. The parameter that is adjusted may be load inductance, L, or load capacitance, C. After each adjustment, an island test is run and time to trip is recorded. If any of these tests results in islanding for longer than the time specified in 3.1.1, the unit fails the test and the test sequence is considered complete.

This test should be performed with the following ratios of real load to inverter output, where both values are given as a percent of inverter full output rating:

Real Load	Inverter Output
25%	25%
50%	50%
100%	100%
125%	100%

The actual tripping time for each test shall be recorded. A single failure of any of these tests is considered a failure of the entire test sequence.

Non-Export Test Procedure
Relay Test

This version of the Non-Export test procedure is intended for stand-alone reverse power and under power relay packages commonly used by utilities

[CMW – Does this test apply to both reverse power and under power relays or just the former?]

{DR: While verifying your changes we noticed Step 3 needed modifications to reflect that the relay should trip at a minimum P.F of 0.1, 84 or 276 degrees, but at a 10 times higher current pickup level. Also, these tests listed below are for a stand alone relay that have potential and currents inputs and they could be electromechanical or microprocessor based. These tests do not generally apply to an inverter since as far as I know, a reverse power function is not available in its package.} [CMW I know of at least one inverter, the Trace Engineering SW series, that has separate utility and load connections and can be programmed to sell back to the utility or not. The capability of reverse power detection—either through separate outputs like the Trace or by monitoring loads or the PCC—is certainly a plausible feature, one that will likely be implemented if there is economic advantage to do so.]

Step 1: Power Flow Test at Minimum, Midpoint and Maximum Pickup Level Settings

Determine the appropriate pickup current for the desired power flow of 0.5 watts (minimum pickup setting). Apply nominal voltage with minimum current setting at 0 degrees power factor. Increase the current to pickup level. Observe the relay's (LCD or computer display) indication of power values. Note the indicated power level at which the relay. trips. The power indication should be within 2 percent of the expected power. For relay's with adjustable settings, this test should be repeated at the midpoint, and maximum settings.

Repeat at power factor 90, 180 and 270 degrees and verify that the relay does NOT operate(measured watts will be zero or negative).

[DR: We suggest using a setting of 0.5 watts for any non-export application]
[CMW - We discussed this setting at length at the last meeting. One issue that was raised was measurement accuracy. A device rated for 100kW or more may not be able to accurately measure 0.5 Watts.

Step 2: Leading Power Factor Test

Apply nominal voltage with a minimum pickup current setting (calculated value for system application) and apply a leading power factor load current in the non-trip direction. Increase the current to pickup level and verify that the relay does NOT operate. For relay's with adjustable settings, this test should be repeated at the minimum, midpoint, and maximum settings.

Step 3 Minimum Power Factor Test

At nominal voltage and with the minimum pickup (or ranges) determined in Step 1, adjust the current angle to 84 or 276 degrees. Increase the current level to pickup (about 10 higher than at 0 degrees) and verify that the relay operates. Repeat for angles 90, 180 and 270 degrees and verify that the relay does NOT operate.

[DR: Modified to reflect DCD's comments that the relay should trip at 84 or 276 degrees but that the pickup current level would be about 10 times higher.]

Step 4 Negative Sequence Voltage Test

Apply nominal voltage and current at 180 degree from tripping direction, to simulate normal load conditions (for 3-phase relays, use Ia at 180, Ib at 60 and Ic and 300 degrees). Remove Phase-1 voltage and observe that the relay does not operate, Repeat for phase-2 and 3.

Step 5 Negative Sequence Current Test

Apply nominal voltage and current at 180 degree from the tripping direction, to simulate normal load conditions (use Ia at 180, Ib at 300 and Ic at 60 degrees). Increase current to pickup level and observe that the relay does NOT operate.

Step 6 Unbalanced Fault Test

Use the settings as shown above, apply 2 times nominal current to Phase 1, to simulate an unbalanced fault and observe that the relay, especially single phase, does not misoperate.

Step 7 – Time Delay Settings Test

Apply Step 1 settings and set time delay to minimum setting. Adjust the current source to the appropriate level to determine operating time, and compare against calculated values. Verify that the timer stops when the relay trips. Repeat at midpoint and maximum delay settings

Step 8 - Dielectric Test

Perform the test described in IEC 414 using 2 kV RMS for 1 minute.

[CMW – I suggest we follow UL 1741, which, for inverters, requires 2xVsys+1000]

[DR: For a stand alone relay the test should be IEC 414. It is not likely that the relay will be included in the inverter package. The difference between the two tests as they relate to their application are not significant and either test could probably be used.]

Step 10 - Surge withstand

Perform the surge withstand test described in IEEE C37.90.1.1989.

[CMW: The C37.90.1.1989 was originally suggested by NY utilities for testing inverters. However, this was thought to be inappropriate by many and NY is now agreeing with the environment described in C62.41 and the procedure described in C62.45. This should eventually become an official part of UL 1741.

[DR: For a stand alone relay the test performed should be IEEE C37 .90.1 1989. It is not likely that the relay will be included in the inverter package. If a reverse power relay or function is used with an inverter system, surge withstand greater than the inverter is not needed. If used on a rotating machine, the C37.90.1 test should apply]

Function Test

Inverters and controllers that include a non-export function shall be factory tested to certify the intended operation of this function. Specific test procedures are currently under consideration.

[CMW – This obviously needs work]

Production Test Procedures

These are intended to be the same requirements as those specified in UL1741 Manufacturing and Production Tests, sections 67 and 68. Alternatively, the dielectric test described in IEC 414 (using 2 kV RMS for 1 minute) may be used in lieu of the dielectric test described below.

Dielectric Voltage-Withstand Test (Hi Pot)

All equipment used for interconnection shall withstand without breakdown, as a routine production-line test, the application of a potential from both input and output wiring

- including connected components, to accessible dead metal parts that are able to become energized
- to accessible low-voltage, limited-energy metal parts, including terminals.

The potential for the production-line test shall be in accordance with Condition A or Condition B of the table below at a frequency within the range of 40-70 Hertz, unless the unit employs a circuit that can be damaged by an ac potential. In the latter case, the test should be done with a dc potential in accordance with Condition C or Condition D. The unit may be in a heated or unheated condition and the test is to be performed on a complete fully assembled unit—it is no intended that the unit be modified or disassembled to complete the test.

Solid state components not relied upon to provide shock protection and that may be damaged by the dielectric potential may be disconnected or the unit tested before the component is electrically connected. The device circuitry may be modified for the test to minimize the potential of damage to such solid state component while retaining representative dielectric stress of the circuit

Production-line test conditions

Unit rating, volts	Condition A		Condition B		Condition C		Condition D	
	Potential, volts ac	Time, seconds	Potential, volts ac	Time, seconds	Potential, volts dc	Time, seconds	Potential, volts dc	Time, seconds
250 or less	1000	60	1200	1	1400	60	1700	1
More than 250	1000+ 2 Va	60	1200+ 2.8 Va	1	1400+ 2.8 Va	60	1700+ 3.4 Va	1
a Maximum marked voltage.								

Test equipment shall include a transformer with a sinusoidal output, a means of indicating the test potential, an audible or visual indicator of breakdown, and a manually reset device to restore the equipment after breakdown or a feature to automatically reject a noncomplying unit.

Test potential is to be indicated by a voltmeter in the output circuit for a. test equipment transformer rating less than 500 VA or, for a rating of 500 VA or more

a) By a voltmeter in the PRIMARY CIRCUIT or in a tertiary-winding circuit,

b) By a selector switch marked to indicate the test potential, or

c) In the case of equipment having a single test-potential output, by a marking in a readily visible location to indicate the test potential. When marking is used without an indicating voltmeter, the equipment shall include a positive means, such as an indicator lamp, to indicate that the manually reset switch has been reset following a dielectric breakdown.

Other test equipment may be used if it can be shown to provide the intended factory control.

Utility Voltage and Frequency Variation Test

All equipment used for interconnection shall disconnect from the utility under application of, as a routine production-line test, the conditions described below

Utility fluctuation verification test conditions

Condition	Simulated utility source		Maximum time (cycles) at 60 Hz[a] before disconnect	
	Voltage (V)	Frequency, Hz		
A	< 0.50 V_{nor}[b]	rated	0.1	(6)
B	0.50 Vnor ≤ V < 0.88 Vnor	rated	2	(120)
C	1.10 Vnor < V < 1.37 Vnor	rated	2	(120)
D	1.37 Vnor ≤ V	rated	0.03	(2)
E	rated	f >60.5	0.1	(6)
F	rated	f <59.3	0.1	(60)

[a] When a utility frequency other than 60 Hz is used for the test, the maximum disconnect time shall not be longer than the time for a utility frequency of 60 Hz regardless of the number of cycles that occur before disconnection.
[b] Vnor is the nominal output voltage rating.
[c] The rate of change in frequency shall be less than 0.5 Hz per second.

Devices with field adjustable trip points shall have the trip factory set points confirmed in accordance with the manufacturer's installation instructions.

The device is not required to be run at full rated output power for this test.

ATTACHMENT B – SAMPLE APPLICATION FORM AND INTERCONNECTION AGREEMENT

This language has not been finalized. Commentary is shown in ***bold italics***. Unresolved language is shown in *underlined text*.

This Interconnection Agreement ("Agreement") is entered into by and between ELECTRICITY PRODUCER'S NAME ("EP"), and ELECTRIC CORPORATION NAME ("EC"), sometimes also referred to herein jointly as "Parties" or individually as "Party".

In consideration of the mutual promises and obligations stated herein, the Parties agree as follows:

1. SCOPE AND PURPOSE

This Agreement allows the EP to interconnect and operate a Generating Facility in parallel with EC's Distribution System. Energy produced by the Generating Facility shall be consumed concurrently with the production of such energy by EP's electrical loads at the Generating Facility's location or, where permitted under section 218 of the Public Utilities' Code a neighboring entity's electric loads lawfully connected to the Generating Facility through non-EC owned wires. This Agreement does not provide for the transmission, distribution, storage, or purchase of electrical power by EC.

2. DESCRIPTION OF GENERATING FACILITY

2.1 Generating Facility Identification Number: ________ (Assigned by EC)

2.2 EP's service Account Number : ___________________ (Assigned by EC)

2.3 Customer name and service address shown on EP's service account (at location of Generating Facility):

____

____

____

2.4 Gross Nameplate Rating of Generating Facility: _____ kW

2.5 Net Nameplate Rating of Generating Facility: _____ kW.

2.6 Expected annual energy production of Generating Facility: ______ kWh.

2.7 Expected Date of Initial Operation: ____________.
(Expected Date of initial Operation not to exceed two years from the date of this agreement.)

2.8 EP's Application For Interconnection, including a description of Generating Facility and a single-line diagram showing the general arrangement of the Generating Facility and Host Facility electric systems shall be attached to this Agreement as Appendix A.

3. DEFINED TERMS

When initially capitalized, whether in the singular or in the plural, the terms used herein shall have the meanings assigned to them either in this Agreement or in Rule 21 of EC's tariffs.

4. TERM AND TERMINATION

4.1 This Agreement shall become effective as of the last date set forth in Section 18, below. The Agreement shall continue in full force and effect until the earliest date that one of the following events occurs: (a) the Parties agree in writing to terminate the Agreement; or (b) At 12:01 A.M. on the 61st day after one Party provides written Notice (pursuant to Section 10, below) to the other Party of its intent to terminate the Agreement.

4.2 EP may elect to terminate this Agreement pursuant to the terms of Section 4.1(b) for any reason. EC may terminate this Agreement pursuant to the terms of Section 4.1(b) only for one or more of the following reasons:

(a) A change in the applicable rules, tariffs, and regulations of EC, as approved or directed by the CPUC, or a change any local, state or federal law, statute or regulation, either of which materially affects EC's ability or obligation to perform its duties under this agreement; or,

(b) EP's failure to comply with the terms of this Agreement within 60 days of EC's Notice of such non-compliance including a description of the required corrective actions to be made; or,

(c) EP's abandonment of the Generating Facility. The generating facility shall be considered to be abandoned by EP if EC determines the Generating Facility is non-operational and EP does not respond to EC's Notice of intent to terminate this Agreement.

4.3 Any agreements attached to and incorporated into this Agreement shall be coterminous with this Agreement unless otherwise agreed by the Parties.

4.4 Upon termination of this Agreement, EP shall disconnect the Generating Facility from EC's Distribution System.

5. GENERATING FACILITY INSTALLATION, OPERATION, AND MAINTENANCE

5.1 EP shall ascertain and comply with the applicable rules, tariffs, and regulations of EC , as approved by the CPUC, and any local, state or federal law, statute or regulation which applies to the design, siting, construction, installation, operation, or any other aspect of the EP's Generating Facility and Interconnection Facilities.

5.2 EP shall connect, operate and maintain the Generating Facility and associated Interconnection Facilities in accordance with Prudent Electrical Practices and the terms of EC's tariffs and rules, as approved by the CPUC, including, but not limited to Rules 2 and 21, copies of which are attached in Appendix B.

5.3 The Generating Facility shall not be connected to EC's Distribution System or modified or relocated to another Point of Common Coupling with the EC's Distribution System without the prior separate express written consent of EC, which consent shall not be unreasonably withheld. This Agreement does not constitute such express written consent.

5.4 EC may limit the operation and/or disconnect or require the disconnection of the EP's Generating Facility from EC's Distribution System at any time, with or without notice, in the event of an Emergency or to correct Unsafe Operating Conditions. EC may also limit the operation and/or disconnect or require the disconnection of an EP's Generating Facility from EC's Distribution System upon the provision of reasonable notice: 1) to allow for routine maintenance, repairs or modifications to EC's Distribution System; 2) upon EC's good faith determination that an EP's Generating Facility is not in compliance with EC's tariffs or rules, as approved by the CPUC.

<u>Commentary</u>: Two of the participants, PG&E & SDG&E, believe the EP should be required to provide maintenance outage schedules. This information may not be required of all EP's, but could be necessary if EC's are expected to rely on EP generation for the proper operation of the EC's Distribution System. Enron proposed to make the notice and coordination of maintenance activities reciprocal. The following language reflects a possible compromise. However, It is unlikely this language will be adopted.

5.5 <u>Each party shall provide the other a schedule of operations indicating expected production and/or line loading levels and maintenance outages. Discretionary maintenance outages shall be scheduled at a time acceptable to both parties.</u>

Commentary: Honeywell and others have proposed that either Rule 21 or this agreement contain language similar to that proposed below that would provide for a "waiver of demand measurement" on the EC meter serving the host utility at any time the DG unit is forced off due to an anomaly or outage of the EC's Distribution System. The EC's assert that customers with or without DG units always have the choice of incurring a demand or curtailing load and that their demand charges are just and reasonable. Further, it would be administratively impractical given the metering and billing systems currently in use by the EC's. This issue is already in our Bin List, and may be addressed in Phase 2 Testimony]

5.6 <u>EP shall not be held liable for any incremental demand charges imposed by EC due to cessation of EP's electricity production as a result of any action by EC.</u>

6. INTERCONNECTION FACILITIES

6.1 Interconnection Facilities necessary to protect EC's Distribution System, personnel and third parties from damage or injury arising out of or connected with the operation of EP's Generating Facility shall be provided, operated and maintained in accordance with the provisions of Rule 21.

6.2 EP shall be solely responsible for the design, purchase, construction, operation, and maintenance of the Interconnection Facilities owned by EP.

6.3 If the provisions of Rule 21 require EP to form an agreement with EC for Interconnection Facilities and/or Distribution System Improvements to be owned and operated by EC, the Parties shall execute an *Interconnection Facilities Financing and Operation Agreement* that provides for the design, installation, operation, maintenance, and ownership of the Interconnection Facilities and/or Distribution System Improvements necessary to interconnect the EP's Generating Facility with EC's Distribution System. Such agreement shall be attached hereto as Appendix C and incorporated herein by this reference.

7. OTHER SERVICES PROVIDED BY EC

EP may be required to contract for other electric services ,as may be approved by the CPUC and provided by EC or others including, but not limited to, metering services, supplemental electric service, and standby service. Where applicable, the Parties shall enter into separate arrangements for such services in accordance with EC's applicable tariffs. Copies of EC's tariff schedules which may be applicable to Electric Producer are attached in Appendix B for reference.

8. INDEMNITY AND LIABILITY

8.1 Each Party as indemnitor shall defend, save harmless and indemnify the other Party and the directors, officers, employees, and agents of such Party against and from any and all loss, liability, damage, claim, cost, charge, demand, or expense (including any reasonable fees, costs or disbursements of outside and/or inside counsel) for injury or death to persons, including employees of any Party, and damage to property including property of any Party arising out of or in connection with (a) the engineering, design, construction, maintenance, repair, operation, supervision, inspection, testing, protection or ownership of, or (b) the making of replacements, additions, betterments to, or reconstruction of, the indemnitor's facilities; provided, however, EP's duty to indemnify EC hereunder shall not extend to loss, liability, damage, claim, cost, charge, demand, or expense resulting from interruptions in electrical service to EC's customers other than EP. This indemnity shall apply notwithstanding the active or passive negligence of the indemnitee. However, no Party shall be indemnified hereunder for its loss, liability, damage, claim, cost, charge, demand or expense resulting from its sole negligence or willful misconduct.

8.2 Notwithstanding the indemnity of Section 8.1 and except for a Party's willful misconduct or sole negligence, each Party shall be responsible for any loss, including, but not limited to, damage to its facilities resulting from electrical disturbances or faults.

8.3 The provisions of this Section 8 shall not be construed to relieve any insurer of its obligations to pay any insurance claims in accordance with the provisions of any valid insurance policy.

8.4 Except as otherwise provided in Section 8.1, no Party shall be liable to another Party for consequential damages incurred by that Party.

Commentary: NEV and Enron proposed to make the following language reciprocal. The utilities do not agree as the utilities see insurance requirements only applying to the EP.

8.5 If EP fails to comply with the provisions of Section 9, EP shall, at its own cost, defend, save harmless and indemnify EC, its directors, officers, employees, and agents, assignees, and successors in interest from and against any and all loss, liability, damage, claim, cost, charge, demand, or expense of any kind or nature (including any reasonable fees, costs or disbursements of outside and/or inside counsel), resulting from injury or death to any person or damage to any property, including the personnel or property of EC, to the extent that EC would have been protected had EP complied with all of the provisions of Section 9. The inclusion of this Section 9.5 is not intended to create any express or implied right in EP to elect not to provide the insurance required under Section 9.

Commentary: ***SCE proposes to replace the entire existing language of Section 8 with the following simpler language based on the indemnity language used in the FERC approved Wholesale Distribution Access Tariff. The participants have not accepted this proposal.***

8.1 EP shall at all time indemnify, defend, and save EC harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from EC's performance of its obligations under this Agreement on behalf of EP, except in cases of negligence or intentional wrongdoing by EC.

8.2 If EP fails to comply with the provisions of Section 9, EP shall, at its own cost, defend, save harmless and indemnify EC, its directors, officers, employees, and agents, assigns, and successors in interest from and against any and all loss, liability, damage, claim, cost, charge, demand, or expense of any kind or nature resulting from injury or death to any person or damage to any property, including EC's personnel or property, to the extent that EC would have been protected had EP complied with all of the provisions of Section 9. The inclusion of this Section 8.2 is not intended to create any express or implied right in EP to elect not to provide the insurance required under Section 9.

9. INSURANCE

Commentary: NEV and Enron proposed to make the following language reciprocal. Honeywell proposes to greatly reduce the coverage levels established by the CPUC for QFs. Solar industry representatives have proposed exemptions for small units and all residential customers. The EC's would be reluctant to abandon or significantly modify these provisions which were previously approved by the CPUC. I doubt that the parties can reach consensus on the indemnity and insurance provisions. Accordingly, these issues may need to be set for CPUC hearings.

9.1 In connection with EP's performance of and obligations under this Agreement, EP shall maintain, during the term of the Agreement, General Liability Insurance with a combined single limit of not less than: (a) one million dollars ($1,000,000) for each occurrence if the Net Nameplate Rating is greater than one hundred (100) kW or greater; (b) five hundred thousand dollars ($500,000) for each occurrence if the Net Nameplate Rating is greater than twenty (20) kW and less than or equal to one hundred (100) kW; and (c) one hundred thousand dollars ($100,000) for each occurrence if the Net Nameplate Rating is twenty (20) kW or less. Such General Liability Insurance shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations.

9.2 The General Liability Insurance required in Section 9.1 shall, by endorsement to the policy or policies, (a) include EC as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that EC shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for payment of premium for such insurance; and (d) provide for thirty (30) calendar days written notice to EC prior to cancellation, termination, alteration, or material change of such insurance.

9.3 Evidence of the insurance required in Section 9.1 shall state that coverage provided is primary and is not in excess to or contributing with any insurance or self-insurance maintained by EC.

9.4 EP shall furnish the required certificates and endorsements to EC prior to Initial Operation. EC shall have the right to inspect or obtain a copy of the original policy or policies of insurance.

9.5 A EP who is self-insured with an established record of self-insurance may comply with the following in lieu of Sections 9.1 through 9.6:

(a) EP shall provide to EC at least thirty (30) calendar days prior to the date of Initial Operation evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under Section 9.1.

(b) If EP ceases to self-insure to the level required hereunder, or if the EP is unable to provide continuing evidence of EP's ability to self-insure, EP shall immediately obtain the coverage required under Section 9.1.

9.6 All insurance certificates, statements of self insurance, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

EC Name
Address ____________________
City ____________________

10. NOTICES AND COMMUNICATIONS

10.1 Any written notice, demand, or request required or authorized in connection with the Agreement shall be deemed properly given if delivered in person or sent by first class mail, postage prepaid, to the person specified below:

EC Name

Address: __________________

City: __________________

EP Name

Address: __________________

City: __________________

10.2 The Parties shall also designate operating representatives to conduct the daily communications which may be necessary for the administration of this Agreement. Such designations, including addresses and telephone numbers, shall be communicated or may be changed by one Party's Notice to the other.

11. REVIEW OF RECORDS AND DATA

If necessary to properly administer the terms of this Agreement, a Party, after providing no less than five days written Notice to another Party, shall have the right to review and obtain copies of operations and maintenance records, logs, or other information pertaining to the Generating Facility or its interconnection with EC's Distribution System.

12. CONFIDENTIALITY

Unless compelled to disclose by judicial or administrative process, CPUC directive, or other provisions of law or as otherwise provided for in this Agreement, each Party will hold in confidence any and all documents and information furnished by the other Party in connection with this Agreement.

13. ASSIGNMENT

EP shall not voluntarily assign its rights nor delegate its duties under this Agreement without the written consent of EC. Any such assignment or delegation made without such written consent shall be null and void. EC's consent to EP's assignment of this Agreement shall not be unreasonably withheld.

14. NON-WAIVER

None of the provisions of this Agreement shall be considered waived by a Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

15. GOVERNING LAW, JURISDICTION OF CPUC, INCLUSION OF EC TARIFFS AND RULES

15.1 This Agreement shall be interpreted, governed, and construed under the laws of the State of California as if executed and to be performed wholly within the State of California.

15.2 This Agreement shall at all times be subject to such changes or modifications by the CPUC as the CPUC may, from time to time, direct in the exercise of its jurisdiction.

15.3 The interconnection and services provided under this Agreement shall at all times be subject to the terms and conditions set forth in the tariff schedules and rules approved by the CPUC and applicable to the electric service provided by EC, which tariffs and rules are hereby incorporated into this Agreement by this reference.

15.4 Notwithstanding any other provisions of this Agreement, EC shall have the right to unilaterally file with the CPUC, pursuant to the CPUC's rules and regulations, an application for change in rates, charges, classification, service, or rule or any agreement relating thereto.

16. AMENDMENT AND MODIFICATION

Any amendments or modifications to this Agreement shall be in writing and agreed to by each Party.

17. ENTIRE AGREEMENT

This Agreement contains the entire agreement and understanding between the Parties, their agents, and employees as to the subject matter of this Agreement. Each Party also represents that in entering into this Agreement, it has not relied on any promise, inducement, representation, warranty, agreement or other statement not set forth in this Agreement.

18. SIGNATURES

IN WITNESS WHEREOF, the Parties hereto have caused two originals of this Agreement to be executed by their duly authorized representatives. This Agreement is effective as of the last date set forth below.

	EP		**EC**
By:	***SAMPLE***	By:	
Name:		Name:	
Title:		Title:	
Date:		Date:	

APPENDIX A

DESCRIPTION OF GENERATING FACILITY AND SINGLE-LINE DIAGRAM, INCLUDING DETAILS OF INTERCONNECTIONS BETWEEN GENERATING FACILITY, HOST FACILITY AND EC

(Provided by EP)

APPENDIX B

TARIFF RULES: “2” and “21”

TARIFF SCHEDULES: ____, ____, and ____

(Note: EC Tariffs are included for reference only and shall at all times be subject to such changes or modifications by the CPUC as the CPUC may, from time to time, direct in the exercise of its jurisdiction.)

APPENDIX C

(When Applicable)

INTERCONNECTION FACILITIES

FINANCING AND OWNERSHIP

APPLICABILITY

This application is for the interconnection of an electrical generating facility that is directly connected to the electrical system of an entity that also receives electric service from EC. This application has been tailored generating facilities that serve all or part of the entity's own electrical requirements, but do not export or sell energy to EC's electric distribution system. If you desire to sell or transmit power to EC, other applications and agreements are available for such arrangements.

PREREQUISITES FOR INTERCONNECTION

This document is solely an application for a contract. It **does not** authorize you to interconnect your generating facility with EC's electric system. You and EC must first sign an *Generating Facility Interconnection Agreement* and comply with the terms of such an agreement. You may be required to install metering or protection devices not supplied with your generating facility prior to receiving permission to interconnect or serve load. You **must not** interconnect your generating facility or serve load until EC provides you with a letter specifically stating that all of the requirements for interconnection have been satisfied and authorizes the interconnection.

INFORMATION REQUIREMENTS

The following information is required by EC to prepare the interconnection agreement you are requesting. Please also submit a "Single-line Diagram" of the system to be installed showing the general arrangement and relationship of the various components, including any customer owned transformers. It may be necessary for EC to request additional information from you or your contractor to clarify the details of your installation.

IDENTIFYING YOURSELF AND LOCATION OF THE PROPOSED GENERATING FACILITY

Applicant (Company Name):		
Contact Person:		
Street Address of Proposed Facility:		
City, State, Zip		
Mailing Address (If different from above)		
City, State, Zip		
Phone Number	Primary ( )	Other ( )
FAX Numbers (optional)		
E-mail Address (optional)		
Current EC Meter Number (If available, attach a copy of a recent bill stub from EC)		

IDENTIFYING YOUR CONTRACTOR OR INSTALLER

Name of Contractor or Installer	
Contact Person	
Street Address	
City, State, Zip	
Phone Numbers	
FAX Numbers (optional)	
E-mail Address (optional)	

DESCRIBING YOUR INSTALLATION (PLEASES USE SEPARATE SHEET(S) IF NECESSARY)

LIST DATA FOR EACH UNIT	Unit 1:	Unit 2:	Unit 3:	Total:
Nameplate Capacity in Kilowatts Please indicate both Gross and Net (of auxiliary load) values.				
Indicate Prime Mover Technology: (I.C. engine, Micro Turbine, Solar/PV, Fuel Cell, Hydro, Wind, etc.)				
Indicate Generator Technology: (DC with Inverter, Induction, Synchronous) Voltage Ratings, Single Phase or Three Phase				
For gas, oil or coal fired units, Indicate if "PURPA" QF Status will be established:				
Indicate the Manufacturer of Pre-Packaged Generator/ Inverter/ Controller(s) If not Pre-packaged, please provide detailed description of Facility:				
Indicate Generator/ Inverter Model Number(s):				
Indicate Estimated Total Monthly Kilowatt-hour Production:				
Indicate Estimated Date of Initial Operation:				

When completed, please send this form to: ________________
EC NAME, P.O. Box _____, City, CA ___

Phone: **FAX:** **E-Mail Messages:**